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Evaluation of Boiler Design Modifications for Enhanced Limb Application

Babcock and Wilcox Co., Barberton, OH

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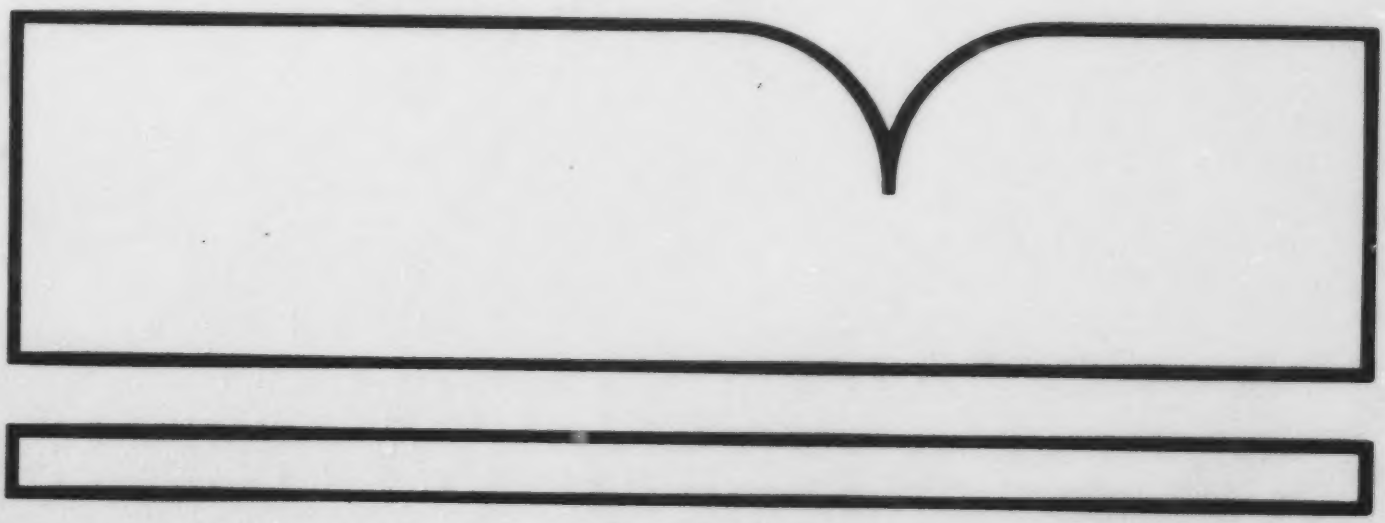

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EVALUATION OF BOILER DESIGN MODIFICATIONS FOR ENHANCED LIMB APPLICATION

by

D.E. Ryan and R. Smolenski

The Babcock & Wilcox Company
Barberton, Ohio 44203

EPA Contract 68-02-4238

Project Officer

David G. Lachapelle
U.S. Environmental Protection Agency
Air and Energy Engineering Research Laboratory
Research Triangle Park, North Carolina 27711

AIR AND ENERGY ENGINEERING RESEARCH LABORATORY
OFFICE OF RESEARCH AND DEVELOPMENT
U.S. ENVIRONMENTAL PROTECTION AGENCY
RESEARCH TRIANGLE PARK, NC 27711

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16. ABSTRACT The report gives results of a study to evaluate the technical and economic impact of designing wall-fired pulverized-coal units to incorporate dry-sorbent sulfur control technology (LIMB). Conventional (non-LIMB) units were set up in three sizes (200, 400, and 600 MW) to burn a low-sulfur (0.48%) subbituminous fuel. LIMB units were then set up to achieve 70% SOx removal using dry sorbent injection. Standard cost estimating procedures were used to evaluate the cost differentials between the conventional and LIMB units. These cost data were used to establish removal cost trends as a function of calcium-to-sulfur (Ca/S) mole ratios and boiler size. The study concluded that it is technically feasible to achieve 70% sulfur removal in a unit burning low-sulfur fuel using only dry sorbent injection. The results also showed that Ca/S ratios between 2.8 and 3.5 can be accommodated without radical alterations to state-of-the-art boiler configurations.

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ABSTRACT

Under EPA sponsorship, a study was conducted to evaluate the technical and economic impact of designing wall fired pulverized coal units to incorporate dry sorbent sulfur control technology (LIMB). Conventional (non-LIMB) units were set up at three MW sizes (200, 400 and 600) to burn a low sulfur (0.48%) sub-bituminous fuel. LIMB units were then set up to achieve 70% SO_x removal using dry sorbent injection. Standard cost estimating procedures were used to evaluate the cost differentials between the conventional and LIMB units. This cost data was used to establish removal cost trends as a function of calcium-to-sulfur (Ca/S) mole ratios and MW size. The study concluded that it is technically feasible to achieve 70% sulfur removal in a unit burning low sulfur fuel using only dry sorbent injection. The results also showed that Ca/S ratios between 2.8 and 3.5 can be accommodated without radical alterations to state-of-the-art boiler configurations.

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CONTENTS

Abstract	ii
Figures	iv
Tables	vi
Introduction and Summary	1
Conclusions	2
Recommendations	3
Objectives and Approach	4
Design Data	
Heat Balances	6
Fuel Analysis	7
Sulfur Removal Requirements	10
LIMB data	
Sorbent Reactions	10
Maximum and Minimum Temperatures	11
Quench Rate and Residence Timae	11
Ambient and Geographical Data	14
Unit Descriptions	
Conventional Units	15
LIMB Unit Design	
Physical Modifications	22
Functional Changes	30
Cost Differentials	38
Economic Analysis	43
References	69
Appendices	
A. Conversions	70
B. Boiler Performance Summary Sheets	72

FIGURES

Number		Page
1	Calcium to sulfur ratio vs. quench rate at 70% sulfur removal	13
2	Typical "Carolina" type coal fired boiler	16
3	Dual register burner	18
4	Superheat, reheat and economizer circuitry	19
5	Furnace circuitry	20
6	Injection point selection curves for 200 MW Unit	25
7	Injection point selection curves for 400 MW Unit	26
8	Injection point selection curves for 600 MW Unit	27
9	Sorbent flow vs. load	29
10	200 MW Conventional Unit	32
11	200 LIMB Unit	33
12	400 Conventional Unit	34

FIGURES
(CONT'D)

Number		Page
13	400 LIMB Unit	35
14	600 MW Conventional Unit	36
15	600 MW LIMB Unit	37
16	Distribution of cost differentials	41
17	Cost differentials vs. Ca/S ratio	42
18	Capital cost differential and SO_2 removal effectiveness vs. MW's at 3.4 Ca/S	48
19	Capital cost differential and SO_2 removal effectiveness vs. MW's at 2.8 Ca/S	49
20	SO_2 removal effectiveness vs. Ca/S ratio	50

TABLES

Number		Page
1	Design Steam Flows, Temperature, and Pressures for Conventional and LIMB Units	7
2	Representative Western Coal: Wyoming Powder River Sub-Bituminous	8
3	Expected SO_2 Captures (Low-Medium-High) Using Calcium Hydroxide as Sorbent	12
4	Design Data Summary for Conventional Units	21
5	Quench Rates and Residence Times for Conventional Units	22
6	Example of Results from Injection Point Selection for 200 MW Unit	28
7	Range of Applicability of Injection Points	28
8	Design Data Summary for LIMB Units	31
9	Base Scope of Supply Used for Conventional Boiler Cost Estimate	38
10	Major Areas of Cost Change Between Conventional and LIMB Boilers	39
11	Cost Differentials ($/KW)	40

TABLES
(CONT'D)

Number		Page
12	Major Economic Premises for Cost of Capital	45
13	Major Economic Premises for Operating and Maintenance Cost	45
14	Optimum Ca/S Ratios	47
15	LIMBCOST Output for 200 MW Unit at 3.4 Ca/S	51
16	LIMBCOST Output for 200 MW Unit at 2.8 Ca/S	54
17	LIMBCOST Output for 400 MW Unit at 3.4 Ca/S	57
18	LIMBCOST Output for 400 MW Unit at 2.9 Ca/S	60
19	LIMBCOST Output for 600 MW Unit at 3.4 Ca/S	63
20	LIMBCOST Output for 600 MW Unit at 2.8 Ca/S	66

INTRODUCTION AND SUMMARY

The Environmental Protection Agency is engaged in a research program to develop improved control technologies for the emission of sulfur and nitrogen oxides (SOx and NOx) from the combustion of fossil fuels. These emissions are important due to their magnitude and apparent link to acid rain. The cause and potential solutions of the acid rain problem are still being debated; however, control of SOx and NOx from power plants is a major element in all proposed control strategies.

The choice of control techniques for acid rain will likely include a mix of technologies to achieve the mandated pollutant reduction at a cost that will minimize the impact on the nation and on specific geographical areas. Commercially available options include: coal switching, coal cleaning, and various types of flue gas desulfurization (FGD) systems. In addition, analysis indicates that low capital cost technology for retrofit to existing boilers would provide further flexibility in a control strategy even at moderate (e.g., 50%) SO_2 removal rates. One such technology is LIMB (acronym for Limestone Injection Multistage Burner), which is based upon the injection of dry sorbents into the boiler for direct capture of SO_2 from the combustion gases. LIMB combines sorbent injection for SOx control with the use of low-NOx burners.

The EPA LIMB program was initiated in 1981 although work in related areas had been previously conducted by the EPA and others. The LIMB program is structured to provide an understanding of the controlling factors in the LIMB process and to establish a basis for the private sector commercialization of the technology.

This engineering study was performed for the EPA as part of the Agency's ongoing effort to investigate all the potential uses of sorbent injection for the control of SOx emissions.

This investigation was performed to determine the technical and cost differentials within the scope of the study between a conventional utility boiler and a utility boiler designed to incorporate the LIMB process. Comparisons were made using nominal 200 MWe, 400 MWe and 600 MWe units. It is noted that the scope of the study considers the boiler shell; auxiliary equipment (i.e., fans, precipitators, flue gas desulfurization equipment, etc.) is not addressed.

Both the conventional and LIMB units were designed to fire a low sulfur (0.48% by weight), subbituminous, western coal. The overall procedure follows: (1) A conventional boiler was designed for each of the three plant sizes to be studied. (2) A LIMB boiler was designed which gave the same output as its conventional sister unit. However, the LIMB unit included the alterations required to allow for 70% of the sulfur introduced into the boiler via the fuel to be removed by sorbent injection without additional downstream gas processing. (3) A cost analysis was performed to determine the cost differentials between the LIMB units and the conventional units.

CONCLUSIONS

The conceptual design work performed to date demonstrates that it is technically feasible to design a LIMB unit burning low-sulfur coal to accommodate Ca/S ratios between 2.8 and 3.5 without radically altering state-of-the-art boiler configurations. In addition, it was determined that based upon an economic analysis utilizing "LIMBCOST", an EPA computer program, the limiting factors when optimizing with respect to the Ca/S ratio are thermodynamic (ie. the lower limit on Ca/S ratio was set by establishing the largest possible residence time cavity and still have a high enough gas temperature entering the convection pass to complete the required heat transfer to surfaces downstream of the cavity).

The conceptual design work also indicated that of the two principal LIMB design criteria (sorbent residence time to 1800F and quench rate to 1600F), the residence time criterion dominated unit configuration considerations. When the design residence time is achieved, acceptable quench rates typically follow.

RECOMMENDATIONS

The work performed to date suggests a need for continuing validation of some of the cost assumptions used in this study, to reflect actual experience as LIMB technology matures. The optimization work performed as part of this study used an AEERL in-house cost estimating program called "LIMBCOST". This program includes a number of algorithms and parameter values for: (1) sorbent injection system (materials handling) costs, (2) base unit capital costs, (3) fuel costs, (4) sorbent costs, and (5) waste disposal, (6) other consumables and (7) maintenance and operating costs. It was beyond the scope of this study to verify these cost assumptions. Therefore, these study results can be considered as initial estimates. In addition, no comparison was made to determine the trade off between LIMB and backend sulfur removal. Any true optimization work would have to consider this issue.

From a technical standpoint, further investigations should center around the injection process and verification of the capture data provided by the EPA. This data is expected to be generated during the EPA'S demonstration programs. However, for purposes of this study, it was assumed that: (1) The nozzles could indeed get the sorbent into the flue gas stream; (2) complete mixing was subsequently achieved after injection; and (3) the expected capture data provided by the EPA is valid.

Planned demonstration testing will provide the data to validate these assumptions and (if necessary) make appropriate modifications to the results of this study.

OBJECTIVES AND APPROACH

STUDY OBJECTIVES

The work done in developing this report was focused on three primary objectives:

The first was to demonstrate the feasibility of designing boilers at 200 MW, 400 MW, and 600 MW to be compatible with the LIMB process.

The second objective was to evaluate the cost differentials between these LIMB compatible units and boilers designed without the LIMB process incorporated (ie. conventional units).

The third objective was to establish cost trends for these units as a function of both megawatt rating and Ca/S ratio.

STUDY APPROACH

The five step approach used during this study is outlined as follows:

First, the design criteria for boilers was established. This included definition of steam conditions, definition of fuel type and a definition of the LIMB parameters to be used.

The second step was to design conventional boilers at 200 MW, 400 MW, and 600 MW which used all of the design parameters established in step 1 except for the LIMB design parameters.

Third, units were designed at the same megawatt ratings used in step 2, but this time the LIMB parameters were incorporated into the design.

Fourth, standard cost estimating procedures were used to establish cost differentials between the conventional units and their sister LIMB units.

Finally, these cost differentials were used to establish and evaluate cost trends as a functional of megawatt rating and as a function of design Ca/S ratio.

DESIGN DATA

HEAT BALANCES

The study scope called for evaluating the impact of designing units which are LIMB compatible at 200 MW, 400 MW and 600 MW's. B&W's contract files were searched to find actual turbine heat balances close to these MW ratings. Further we decided to use turbine data from the same manufacturer because idiosyncrasies between turbine manufactures design practices could lead to uncertain results when comparing boilers designed to different manufacturer's specifications.

General Electric turbine data was found close to the 600 MW and 400 MW sizes (621 MW and 447 MW gross output, respectively) however, we were unable to find turbine data for a 200 MW unit at 2400 psi.* Therefore, the required design information was extrapolated from the 621 MW and 447 MW data. The resultant gross output was 196 MW. This data is presented in Table 1.

Throughout the report the units sizes will be referred to as nominal 200, 400 and 600 MW. However, all trends and comparisons are based on the actual gross output ratings. Furthermore, the steam side design data (ie. steam flows, pressure, and temperatures) are the same for the conventional and LIMB unit at any given MW rating.

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*Readers more familiar with SI units may use the conversion factors tabulated in Appendix A.

TABLE 1. DESIGN STEAM FLOWS, TEMPERATURES, AND PRESSURES FOR CONVENTIONAL AND LIMB UNITS

NOMINAL MW RATING	200	400	600
Gross Power Output, MWe	196	447	621
Main Steam Flow, 1000 lb/hr	1330	3034	4224
Reheat Steam Flow, 1000 lb/hr	1195	2707	3764
Main Steam Temp. Lvg. Unit °F	1005	1005	1005
Reheat Steam Temp. Lvg. Unit, °F	1005	1005	1005
Feedwater Inlet Temp., °F	478	485	490
Reheat Steam Inlet Temp., °F	622	633	641
Superheater Outlet Press., psig	2620	2620	2620
Reheat Outlet Press., psig	531	564	580
Reheat Inlet Press., psig	556	589	612

FUEL ANALYSIS

The fuel utilized for this study was taken from the EPRI Technical Assessment Guide (Reference 1). It is representative of a typical low sulfur western subbituminous fuel and is used by EPRI as their standard analysis. The average analysis and range values are listed in Table 2. Several key characteristics of this fuel are: high grindability, high moisture content, low ash content, high slagging and medium fouling potential, and low silica and alumina content. Average values were used for all combustion calculations, and range values were used to evaluate slagging and fouling potential.

TABLE 2. REPRESENTATIVE WESTERN COAL: WYOMING POWDER RIVER SUB-BITUMINOUS

Proximate Analysis, wt%	Average	Range
Moisture	30.4	26 to 34
Volatile Matter	31.1	29 to 34
Fixed carbon	32.1	29 to 44
Ash	6.4	
	100.0	
Gross Heating Value, Btu/lb	8,020	7,400 to 8300
Grindability, hardgrove	64	
Total sulfur, wt%	0.48	0.25 to 1.0
Ultimate Analysis, wt%		
Moisture	30.40	6 to 24
Carbon	47.85	46 to 50
Hydrogen	3.40	3 to 3.7
Nitrogen	0.62	0.5 to 0.8
Chlorine	0.03	0 to 0.1
Sulfur	0.48	0.25 to 1.0
Oxygen	10.82	9 to 12
Ash	6.40	4.4 to 11.7
	100.00	
Sulfur Forms, wt%		
Pyritic	0.11	
Organic	0.33	
Sulfate	0.04	
	0.48	

(CONTINUED)

TABLE 2 (CONCLUDED)

Ash Analysis, wt%	Average	Range
Silica, SiO_2	31.6	25 to 36
Ferric Oxide, Fe_2O_3	4.6	2.7 to 5.5
Alumina, Al_2O_3	15.3	13 to 17
Titanium Oxide TiO_2	1.1	0.9 to 1.5
Calcium Oxide, CaO^2	22.8	19 to 30
Magnesia, MgO	4.7	3.5 to 5.6
Sulfur Trioxide, SO_3	16.6	12 to 21
Potassium Oxide, K_2O	0.4	0.2 to 0.8
Sodium Oxide, Na_2O^2	1.3	0.9 to 2.1
Phosporous Pentoxide, P_2O_5	0.8	0.2 to 1.5
Undetermined	8.0	
Total	100.0	

Ash Fusion, ^oF	Reducing	Oxidizing
Initial Deformation	2,140	2,210
Softening (H = W)	2,195	2,255
Hemispherical (H = 1/2W)	2,230	2,290
Fluid	2,270	2,330

SULFUR REMOVAL REQUIREMENTS

The New Source Performance Standard (NSPS) requirement for this fuel is 70% removal of the sulfur in the fuel. This removal efficiency was to be maintained at all continuous operating conditions (per the direction of the EPA project officer). As a result the process was established for 70% removal at all boiler loads above 25% of Maximum Continuous Rating (MCR).

LIMB DATA

Sorbent and Reactions

Hydrated lime was used as the sorbent in this study (per the direction of the EPA project officer). The reactions associated with the process are as follows:

First, the hydrate is converted to calcium oxide and water.

$$Ca(OH)_2 + Heat = CaO + H_2O$$

Then, in the presence of oxygen and sulfur, calcium sulfate is formed.

$$CaO + SO_2 + \tfrac{1}{2}O_2 = CaSO_4 + Heat$$

The dehydration process is endothermic, while the sulfation reaction is exothermic. The result is a very minor overall heat consumption which theoretically could reduce boiler efficiency. For this study this efficiency reduction was considered negligible due to the low level of sulfur in the fuel. In addition, the oxygen level in the combustion gas (8.4% O_2 by weight) was considered adequate for the reaction to occur.

Maximum and Minimum Temperatures

A significant amount of research has been performed to identify the temperature "window" within which the calcination and sulfation reactions occur. Much of this research has been surveyed by the investigators involved in the LIMB demonstration project. Based upon the conclusions reached thus far, 2300F was established as the upper limit on the injection point temperature to avoid excessively high rates of sintering while still providing for a sufficiently high rate of calcination.

Additionally, temperatures higher than 2300F are likely to result in the sulfation reaction proceeding more rapidly than the SO_2 can diffuse into the pores of the CaO particles. This phenomenon would severely limit the calcium utilization potential.

The low end of the useful window was established at 1600F. While the sulfation reaction does occur at temperatures lower than 1600F, the reaction rate has slowed appreciably causing the required residence time to increase beyond levels considered practical for this type of system.

Quench Rate and Residence Time

Within the temperature window defined above, two related parameters have been shown to impact the ratio of calcium injected to sulfur removal. These two parameters are quench rate and residence time.

Quench rate is defined as the temperature change from the point of injection to the exit of the window (1600F) divided by the time spent within the window.

$$\text{Quench Rate} = (T_{g1} - 1600F)/n$$

Where: T_{g1} = injection point temperature (F) and
n = time within the window (seconds).

A tabulation of Ca/S versus quench rate was provided by the EPA for use in this study (See Table 3). Note that for each point in the matrix, a range of removal rates is given. All the design work for this study was based upon using the high end of the range per the recommendation of the EPA. A curve of Ca/S versus quench rate was developed for 70% removal (See Figure 1). This curve provided a quick reference during the course of the design work.

TABLE 3. EXPECTED SO_2 CAPTURES (LOW-MEDIUM-HIGH) USING CALCIUM HYDROXIDE AS SORBENT

Quench Rate (°F/Sec)	Ca/S RATIO				
	2.0	2.5	3.0	3.5	4.0
1000	32-34-37	40-42-44	49-50-51	56-57-58	63-64-65
900	35-37-40	44-45-46	53-54-56	60-62-63	68-69-70
700	40-43-46	49-51-54	57-59-62	65-67-69	73-75-76
500	45-49-52	53-57-60	61-65-68	69-71-72	77-80-82
300	49-53-58	58-62-66	66-70-74	74-78-81	82-85-88

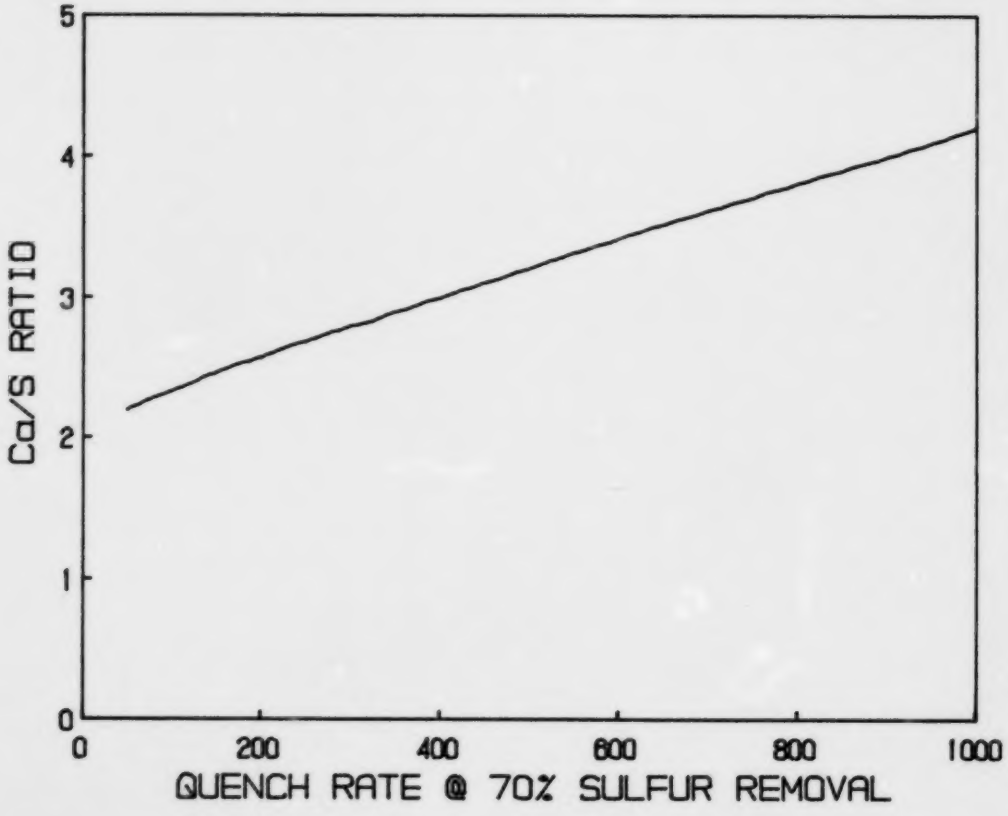


FIGURE 1. CALCIUM TO SULFUR RATIO VS. QUENCH RATE AT 70% SULFUR REMOVAL

The second parameter is residence time. Theoretically, the quench rate could be changed by adding or subtracting residence time at either the high or low end of the temperature window. However, research indicates that the time spent in the high end of the window is more effective. Therefore, a second criterion was set to allow approximately one second of residence time between the injection point and the point at which the gas temperature reaches 1800F. In the final analysis the high temperature residence time criteria dictated the unit configuration since achieving it virtually guaranteed that the desired quench rates would be obtained.

AMBIENT AND GEOGRAPHICAL DATA

The EPRI Technical Assessment Guide (TAG) was used to define ambient conditions and site parameters. The following information was taken from Sections 2.4 and 2.6 of TAG (Reference 1):

The plant location is assumed to be in the Wisconsin-Illinois area in the West Central Region of the United States. The site is assumed to be clear and level with no special problems. The units were designed for Seismic Zone 1 at an elevation of 600 feet above mean sea level. The dry-bulb air temperature is assumed to be 60 ^{o}F (based on annual average maximum daily temperature for the Chicago area). The atmospheric pressure was specified as 14.4 psia. The moisture content in the air was taken as 0.013 lb water per lb of dry air.

UNIT DESCRIPTIONS

CONVENTIONAL UNITS

To provide a baseline for comparison of the LIMB boilers, three (3) conventional units were designed. These units used the "Carolina" type configuration, which is B&W's standard for pulverized coal firing. A typical unit is illustrated in Figure 2. This design provides for a large, open lower furnace zone that: (1) insures complete combustion of the pulverized coal, (2) provides adequate cooling of the combustion gases prior to entering the closely spaced (less than 15 inches on centers) superheat and reheat tubes, and (3) keeps the average flame temperature low to help minimize NOx formation.

Wide spaced (54 inches on centers minimum) platen superheat sections are located in the upper furnace. Hot combustion gas from the furnace passes through the secondary (or finishing) superheater banks and the pendant reheater banks. The gas then turns and flows downward through two parallel paths containing horizontal reheater banks and primary superheater banks. The "parallel downpass" arrangement is B&W's standard when a wide control range (60 to 100% of MCR) is required. Each path is equipped with a damper that enables the operator to bias flue gas as needed to maintain reheat outlet temperatures.

Each parallel downpass also contains economizer surface. The gas flows through the economizer banks and out to the air heater.

A Rothemuhle "twinflow" air heater was used. This type of air heater contains both primary and secondary air heating surfaces within a common housing. The heated primary air dries, classifies, and transports coal in the MPS roll and race type pulverizers. The fuel and air mixture exits the top of the pulverizer through a set of pipes that directs the mixture to the windbox and burners.

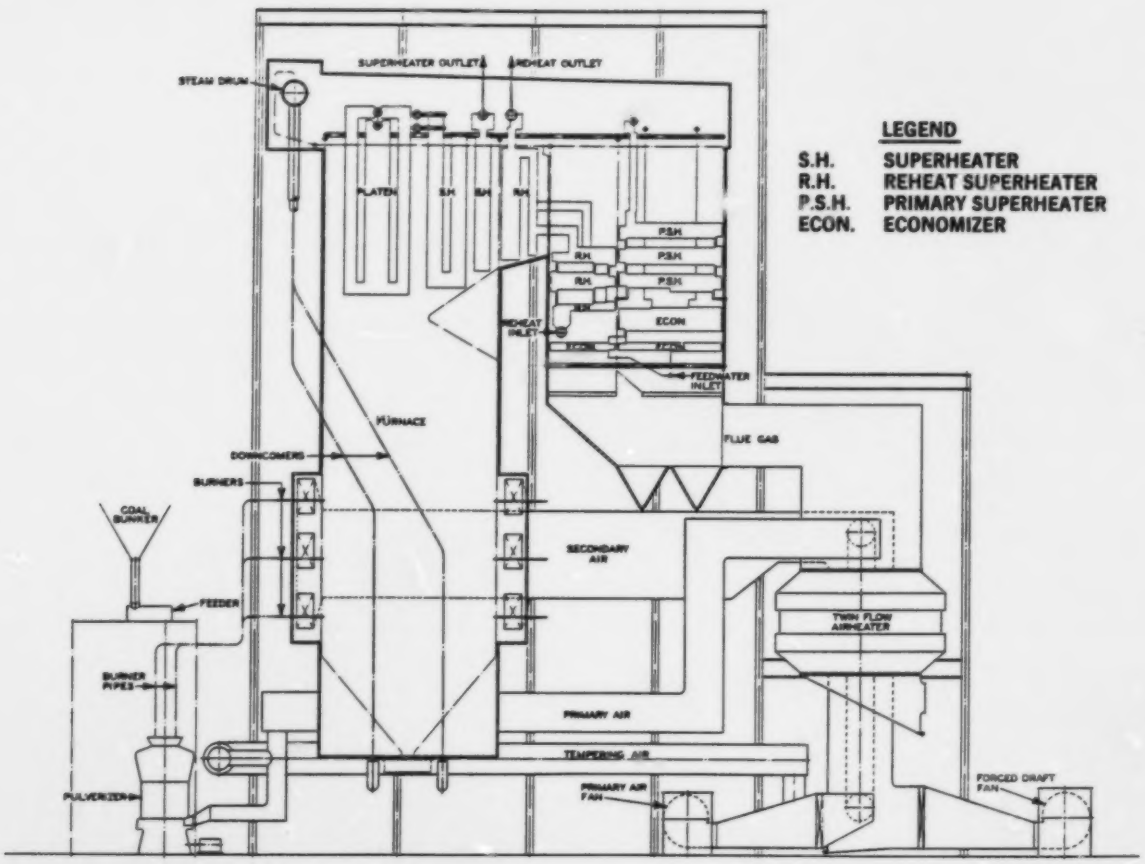


FIGURE 2. TYPICAL "CAROLINA" TYPE COAL FIRED BOILER

Standard "dual-register" low NOx burners (See Figure 3) have been utilized. These burners are designed to provide a fuel-rich inner flame core by controlling the velocity profile of the heated secondary air. Secondary air flow to the burners is controlled at each burner level utilizing compartmented windbox with individual feeder ducts. With this arrangement air flows and fuel flows can be matched and controlled to minimize both furnace slagging and NOx formation. This burner arrangement in combination with the sizing of the lower furnace provides NOx levels at or below the NSPS requirement of 0.6 $lb/10^6$ Btu.

Convection bank tube spacings and bank depths have been set to account for the slagging and fouling characteristics (high slagging, medium fouling) of the fuel. Similarly, sootblower requirements in both the furnace and convection pass are determined based upon these characteristics.

The water and steam flow circuitry for the convection pass is illustrated in Figure 4. The circuitry for the natural circulation furnace enclosure is similarly illustrated in Figure 5.

Specific design data for the three conventional units are summarized in Table 4. A more detailed tabulation is given on the Summary Sheets included in Appendix B of this report. Figures 10, 12, and 14 on pages 32, 34, and 36 depict the general arrangement and specific dimensions for each of the conventional units.

It should be noted that these units were all sized in a manner consistent with the approach that would be taken in a competitive bidding situation. No special considerations were made to minimize the changes required to incorporate LIMB.

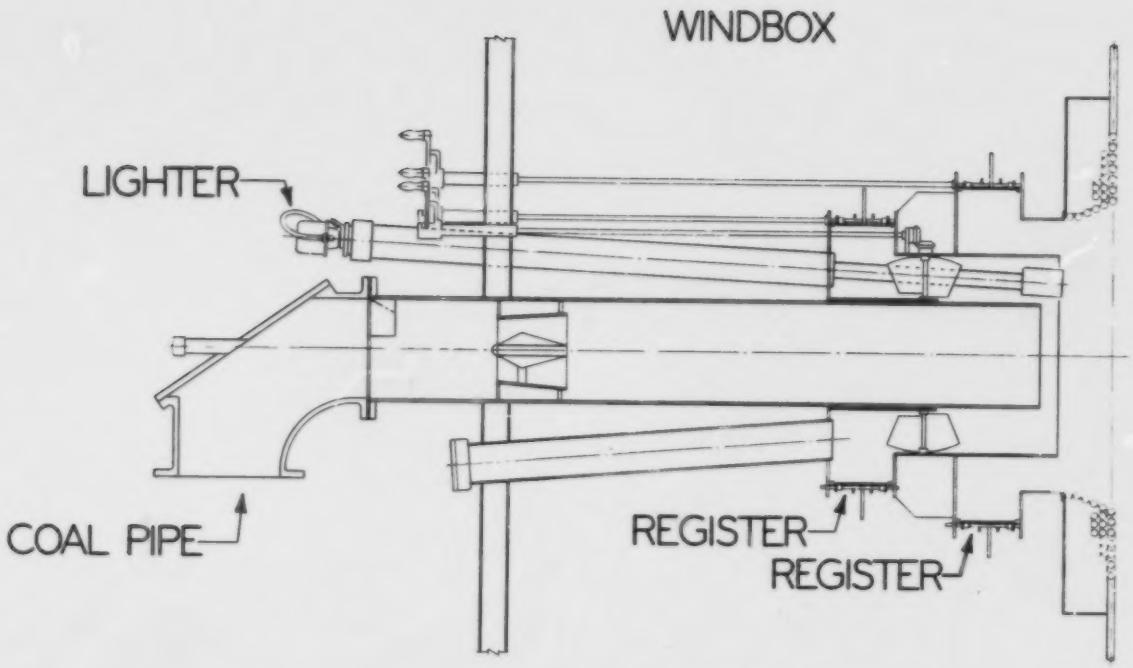


FIGURE 3. DUAL REGISTER BURNER

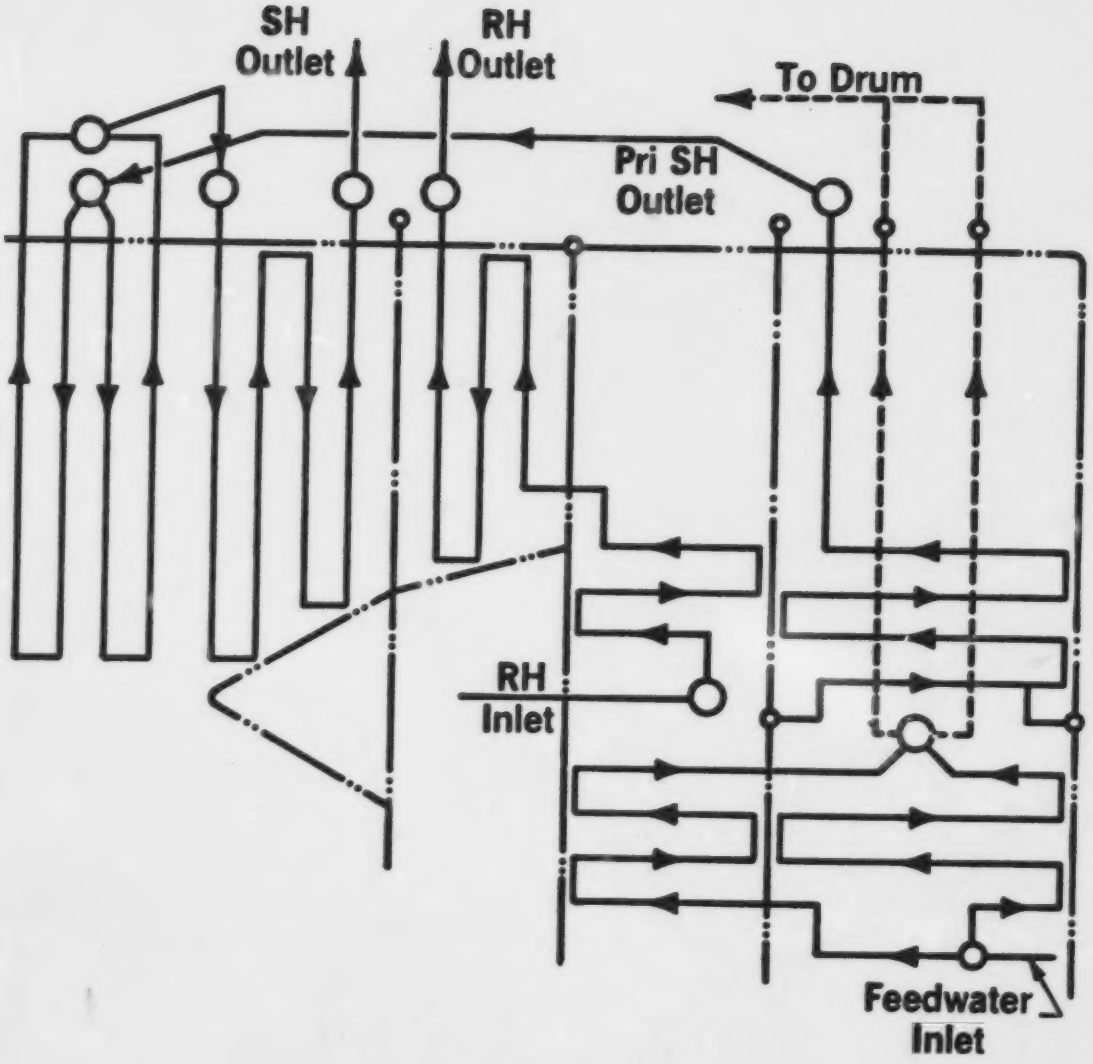


FIGURE 4. SUPERHEAT, REHEAT AND ECONOMIZER CIRCUITRY

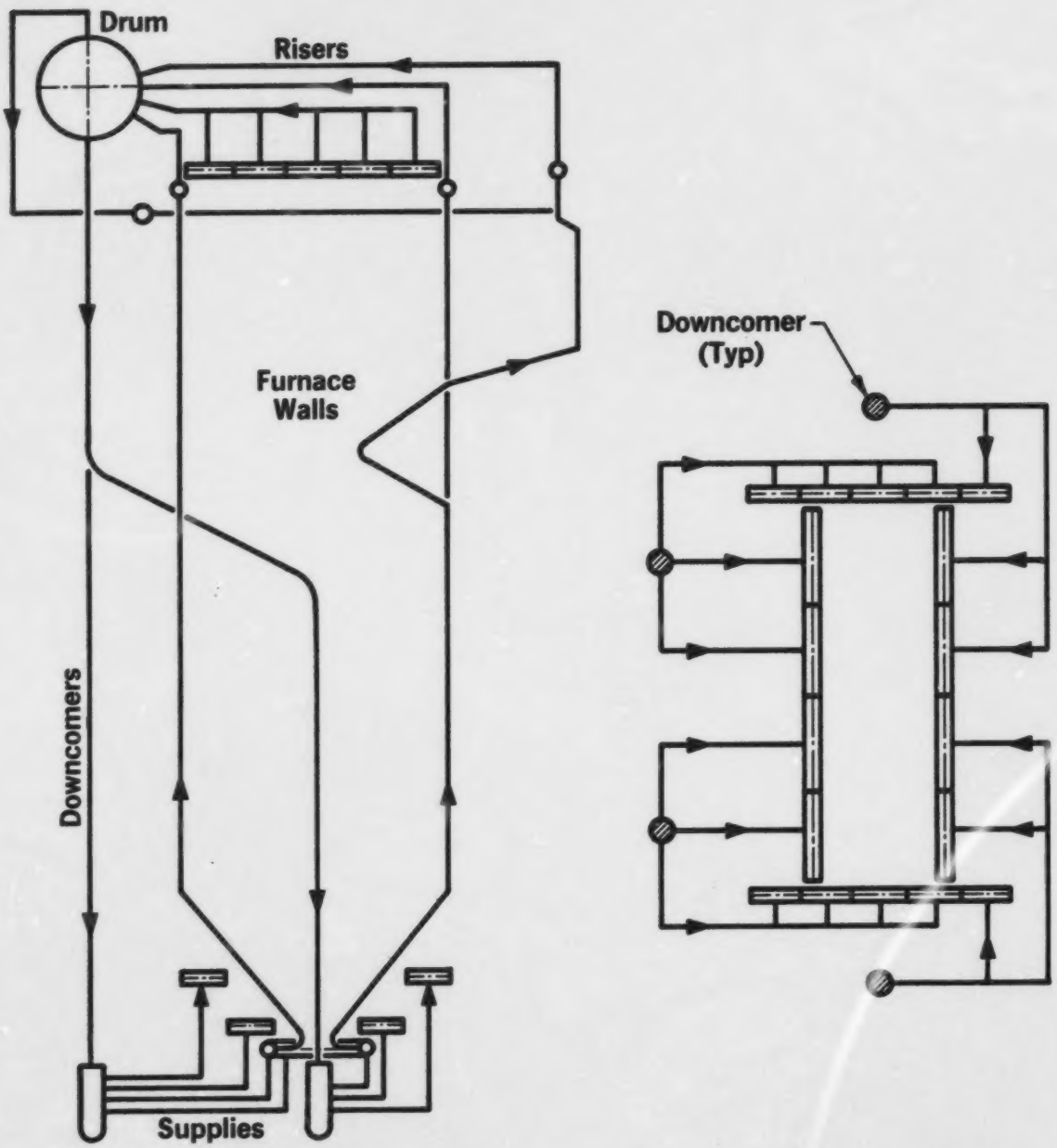


FIGURE 5. FURNACE CIRCUITRY

TABLE 4. DESIGN DATA SUMMARY FOR CONVENTIONAL UNITS

NOMINAL MW RATING	200	400	600
Gross MW	196	447	621
Steam Flows			
Superheat	1331	3034	4225
Reheat	1195	270	3764
Superheater Outlet Pressure	2620	2620	2620
Furnace Width, ft.	37	58	64
Furnace Depth, ft.	40	45	51
Furnace Height, ft.	125	152	181
No. of Burners	16	30	42
No. of Pulverizers	4	5	6
Pulverizer Size	MPS-67	MPS-89	MPS-89
Fuel Rates, 1000 lb/hr	232.8	524.5	724.5
Gross Efficiency, %	84.54	84.58	84.59
Air Heaters			
Type	Twinflow	Twinflow	Twinflow
Quantity	1	1	2
Diameters, Meters (Overall/Primary Section)	12.5/6.7	19/10	14/7.5

LIMB UNIT DESIGN

Physical Modifications

The next phase in the study was to determine what modifications to the baseline configuration were required to achieve 70% removal at a reasonable Ca/S ratio. The first step in this process was to establish the quench rates and residence times for the baseline units. This data is summarized in Table 5. All data are at MCR load and assume injection points in the platen superheater zone.

TABLE 5. QUENCH RATES AND RESIDENCE TIMES FOR CONVENTIONAL UNITS

Nominal MW	200	400	600
Gross MW	196	447	621
Quench Rate (to 1600F), °F/s	1026	1285	1300
Residence Time (to 1800F), s	0.4	0.4	0.4
Ca/S Ratio required for 70% removal	4.25	4.7	4.8

Clearly, the residence time requirements previously established the (time between injection and 1800F = 1 second) are not met. Even if the residence time were satisfied, the quench rates require unacceptably high Ca/S ratio. Therefore, it was obvious that the arrangement had to be altered to achieve the required residence time.

Ideally, this residence time could be achieved by the insertion of an appropriately sized isothermal cavity downstream of the injection point. Such a cavity would provide the required residence time, but have no impact on the performance and/or quantity of heating surface downstream of the cavity.

In practice such a cavity is unachievable, although the isothermal condition could be approached by lining the enclosure walls with a layer of refractory material. While this idea is conceptually feasible it was abandoned based on practical considerations.

A point in fact, one of the most frequent maintenance problems on utility boilers (especially older units) is the repair of refractory materials. As a result boiler designs have evolved in such a manner as to minimize the use of these materials. Therefore, to incorporate a large refractory lined cavity in a LIMB design would constitute a large step backward from the standpoint of availability and maintainability.

The resultant conclusion was to use a large water and steam cooled cavity just downstream of the injection point. For the purposes of the study, this cavity was sized to attain the required one second residence time. Typically, sizing the cavity for this criterion resulted in acceptable quench rates and Ca/S ratios. It was recognized that this sizing criteria might not result in the optimum quench rate. Unfortunately, determination of the optimum quench rate would require a number of iterations of the boiler sizing and cost estimating loop. The time constraint of the study did not allow for this type of iterative procedure. However, a method was developed to obtain an estimate of the "optimum" quench rate. (This method is described in the Economic Analysis Section of this report.)

The selection of injection points was divided into two distinct steps. The first step was to establish the injection location at the MCR design point. This decision was principally one of determining the point at which the 2300F temperature occurred. Additional factors included flue gas flow patterns and accessibility of the injection point. For the 400 MW and 600 MW units, the mid-point of the platen superheaters was chosen. Injection at this point was proposed to be done by water cooled lances projecting through the front wall of the upper furnace. This location was selected due to the existence of a reasonably uniform gas flow pattern without significant recirculation. More importantly, the desired temperature level this location for units designed for this type of fuel.

The MCR injection point for the 200 MW unit differs principally in the fact that there are no furnace platens on the 200 MW LIMB unit. As a result, sidewall mounted injection ports were located in the upper furnace zone instead of lances. This method was not used on the 400 and 600 MW units because effective mixing of the sorbent would have been prevented by the platen superheater sections. With the MCR injection point set, the residence time cavity was sized and the balance of the heating surface was arranged.

The second step was to determine the need for location of additional injection points to handle reduced load conditions. The criteria for selection of these additional injection points were: (1) the 70% removal requirement at all loads down to 25% of MCR and (2) minimization of the number of injection locations and thus, the number of injection point changes over the load range.

A series of curves were developed to assist in this phase of the design work; these curves describe the relationships between boiler load and a three significant design parameters. These design parameters were: 1) Gas temperature at the injection point 2) Residence time from the injection point to 1800F gas temperature and 3) Quench rates from the injection point to 1600F gas temperature. These curves are shown for each unit size in Figures 6, 7, and 8. In all of these figures, three injection points were assumed. The first, Point A, was the MCR injection location. The second and third , Points B and C, were arbitrarily set at a horizontal plane extending across the furnace from the tip of the arch (Point B) and at another horizontal plane located 12 ft below the arch work point (Point C).

To use the curves, some constraints must be defined. The first constraint is that injection cannot occur at a gas temperature above 2350F (this is slightly above 2300F to allow time for the sorbent to disperse into the gas steam). The second is that a minimum residence time of approximately one second must exist between the injection point and 1800F gas temperature.

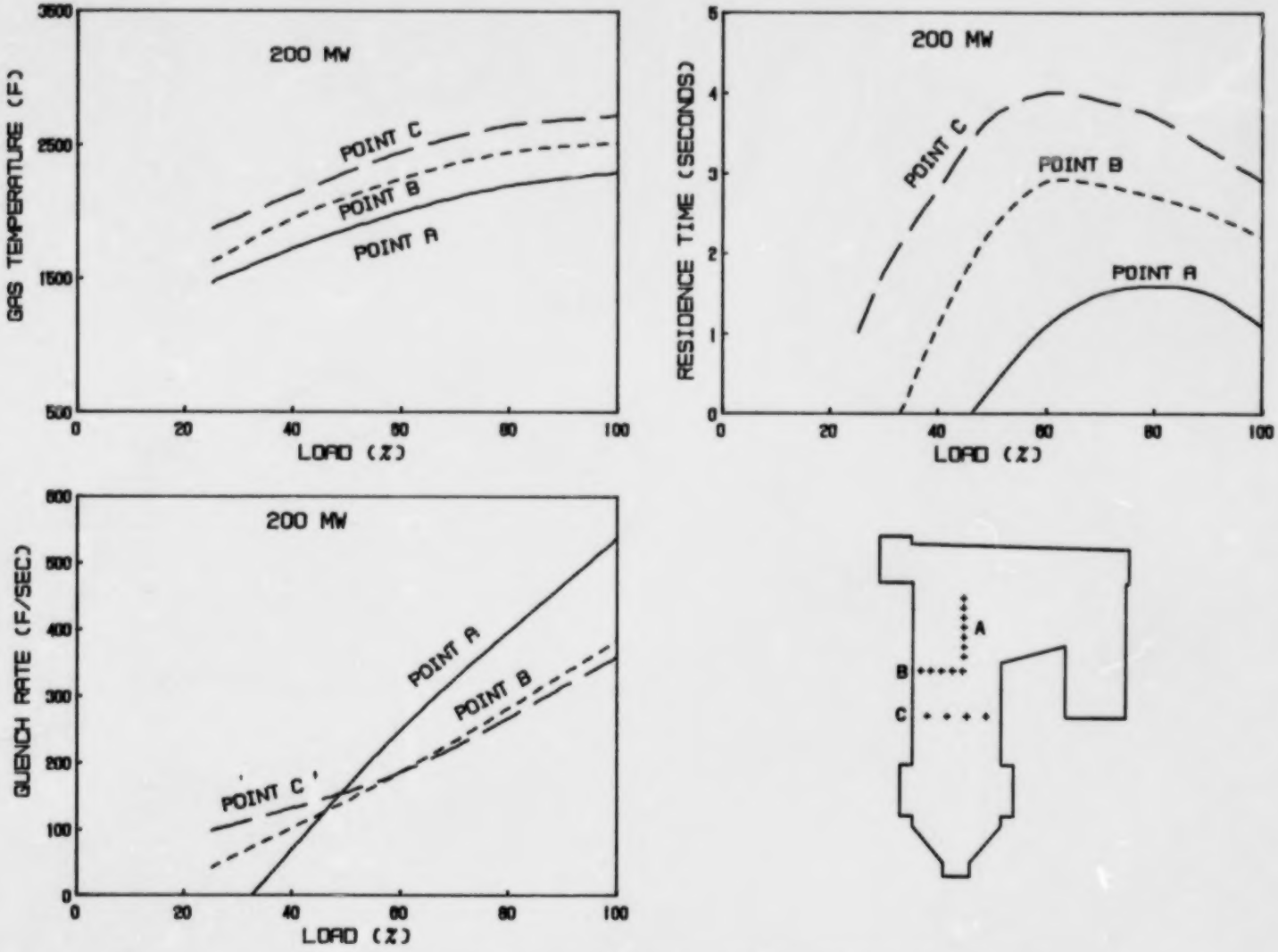


FIGURE 6. INJECTION POINT SELECTION CURVES FOR 200 MW UNIT

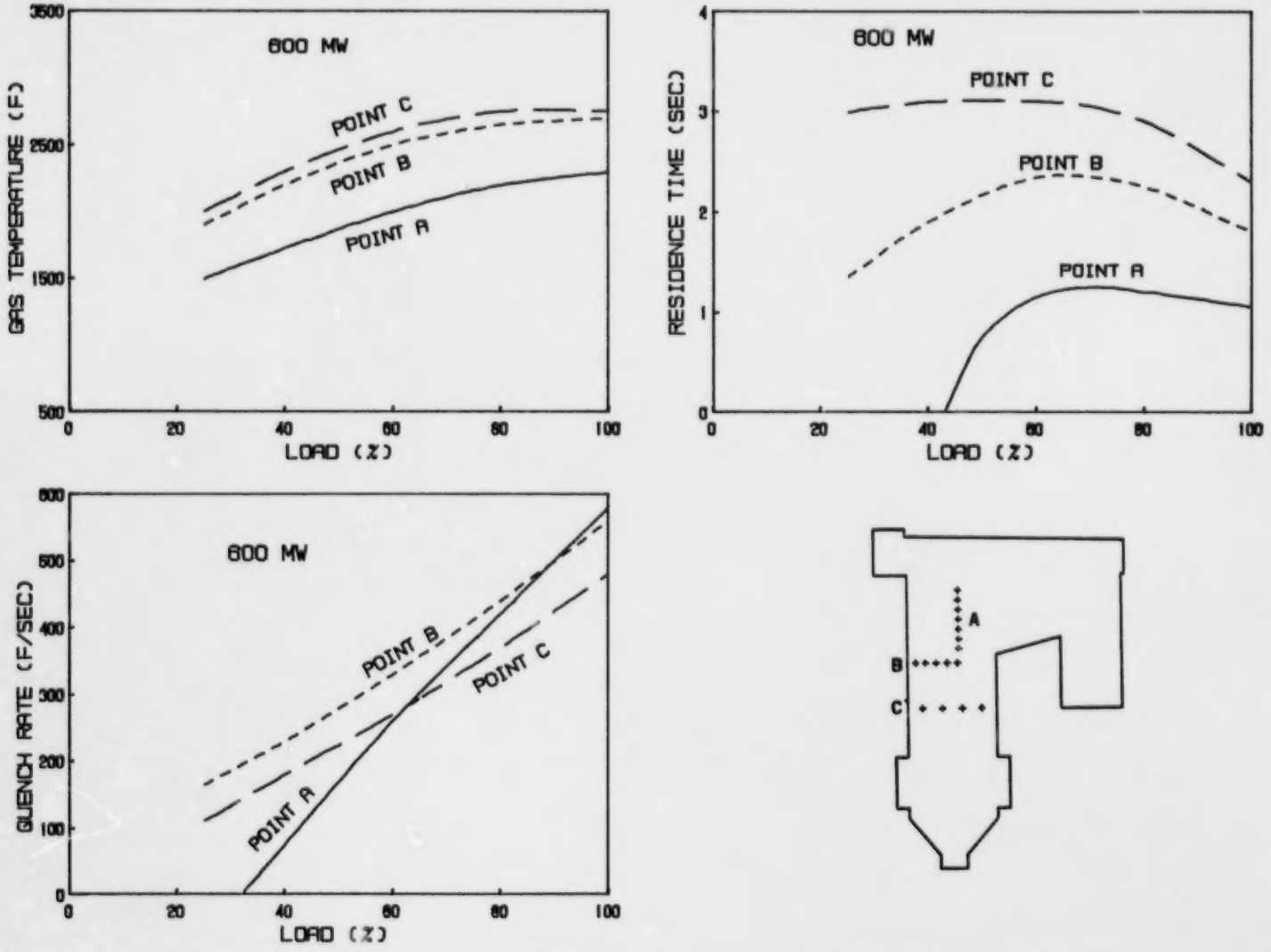
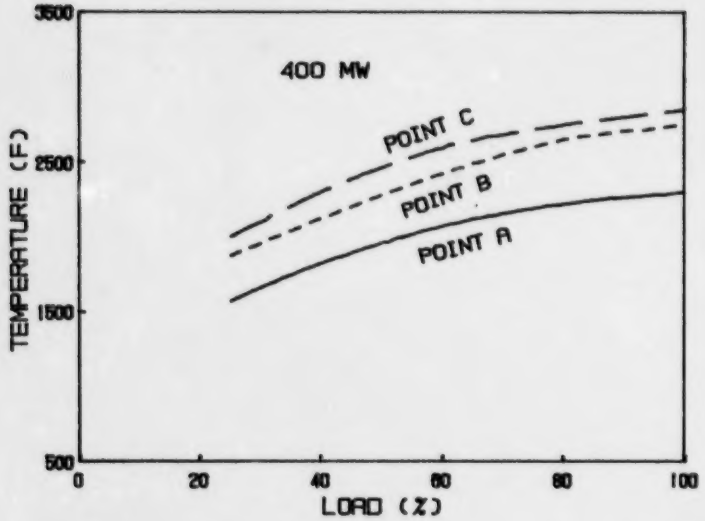
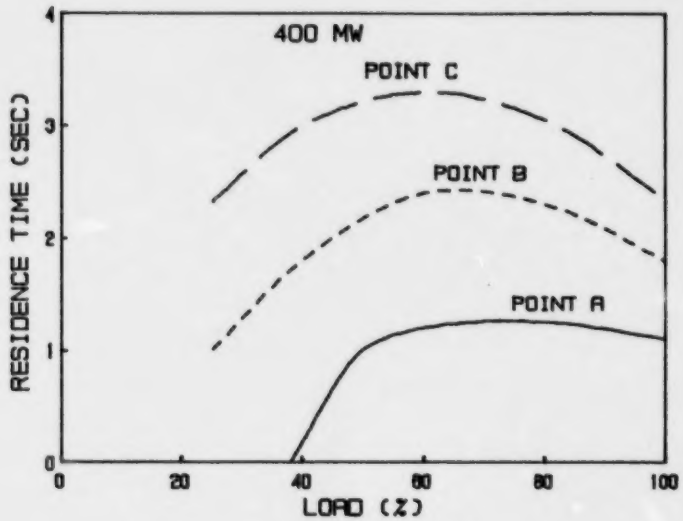
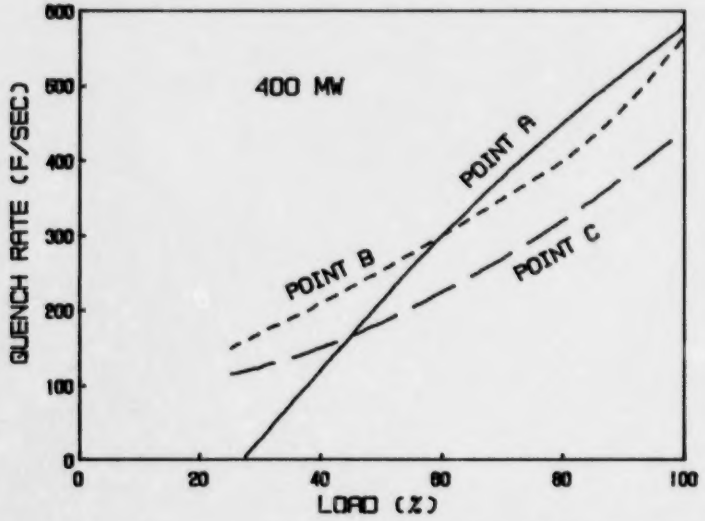


FIGURE 7. INJECTION POINT SELECTION CURVES FOR 400 MW







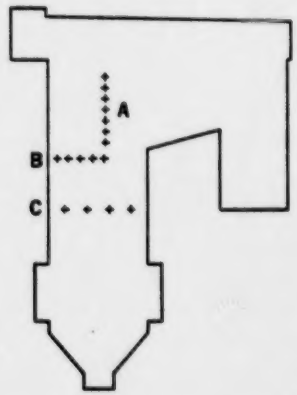


FIGURE 8. INJECTION POINT SELECTION CURVES FOR 600 MW UNIT

To illustrate their use, take the following example for the 200 MW unit. First, use the temperature vs. load curve to establish the maximum load that sorbent can be injected at each point (Tg=2350F). For Point B, this is approximately 65% load and for Point C, it is 50% load. Now enter the residence time vs. load curve to determine the lowest load that yields a residence time (above 1800F) greater than one second. For Point A, this is 58% load, Point B 39% load, and Point C any load. The quench rate vs. load curve then gives the quench rate and, therefore, the Ca/S ratio for each injection point. These results are summarized in Table 6.

TABLE 6. EXAMPLE OF RESULTS FROM INJECTION POINT SELECTION FOR 200 MW UNIT

			QUENCH RATE		Ca/S	
	MAX	MIN	MAX	MIN	MAX	MIN
Injection Point	LOAD	LOAD	LOAD	LOAD	LOAD	LOAD
A	100%	58%	543	240	3.3	2.7
B	65%	39%	210	100	2.6	2.3
C	50%	25%	160	100	2.5	2.3

This same procedure was used on the 400 MW and 600 MW units. The results of this application are summarized in Table 7. Figure 9 illustrates sorbent flow as a function of boiler load using these injection points. Note that some overlap is present between injection points. This is deliberate and represents the desire to avoid sharp break points and the resultant need to effect rapid changeovers from one point to another as load conditions change.

TABLE 7. RANGE OF APPLICABILITY OF INJECTION POINTS

	A	B	C
UNIT SIZE	LOAD RANGE		
200 MW	100 - 58	65 - 39	50 - 25
400 MW	100 - 51	55 - 25	Not Required
600 MW	100 - 50	50 - 25	Not Required

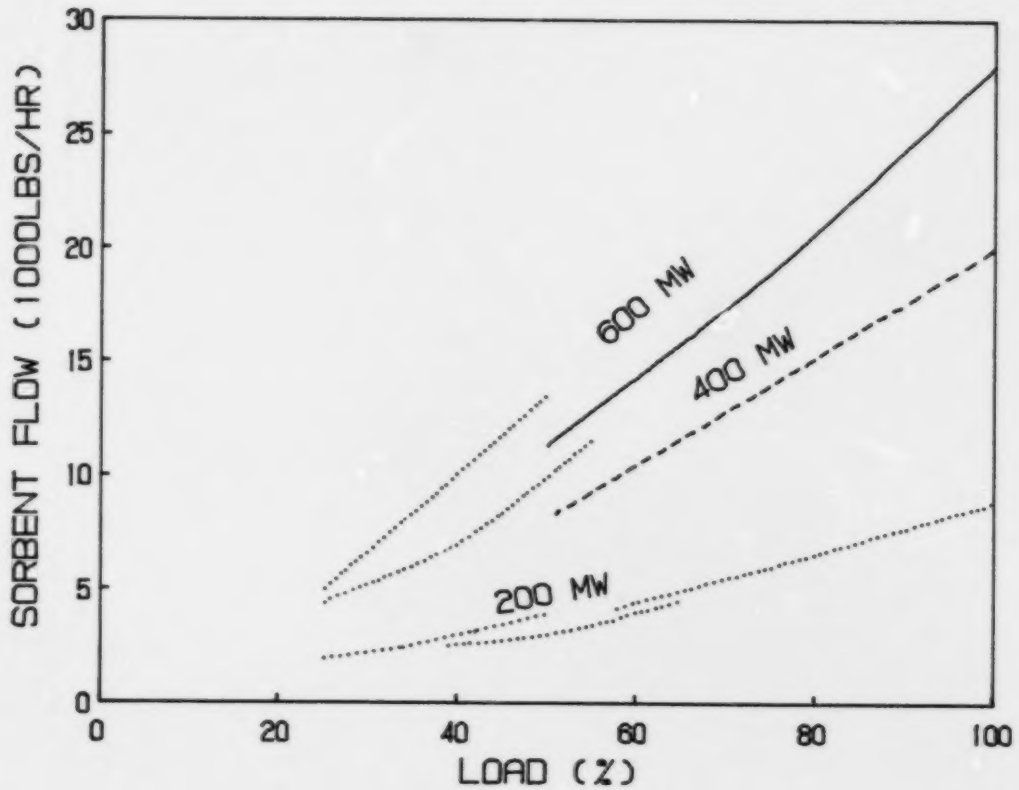


FIGURE 9. SORBENT FLOW VS. LOAD

Functional Changes

Efficiency is impacted by this process in three ways. First, as previously noted the reactions have a minor impact. Dehydration is an endothermic reaction, and represents a minor loss in gross boiler efficiency. The sulfation reaction is exothermic, and actually adds to the energy available for transfer to the heating surfaces. Since the sulfur level in the fuel is low, the net impact on boiler efficiency was judged to be negligible for purposes of calculating boiler performance. Second, the transport and injection air has an observable impact on unit performance. Pressurized air was used to transport the sorbent into the furnace. This additional "excess" air (approximately 1% over that required for combustion) represents a minor loss in boiler efficiency.

The third impact is the heat loss attributable to the heat picked up and rejected by the water cooled injection lances. This heat loss was calculated and factored into unit performance. Since the 200 MW unit uses sidewall injection points, that loss does not apply to this unit.

While the increase in ash loading due to sorbent injection was significant, no decreases in allowable flue gas design velocities were made for two reasons: (1) The new ash loading is still below the level requiring an adjustment due to the relatively low initial ash and sulfur contents in the fuel; and (2) the particulate being added is not considered abrasive in nature.

Based on the work performed in support of the EPA's wall-fired LIMB demonstration (EPA contract 68-02-4238), no adjustment was made to sootblowing requirements to account for sorbent injection. This conclusion was made by the Demonstration Project investigators based on a combination of experimentation and literature reviews.

Figures 11, 13 and 15 depict the resultant LIMB unit configurations. For the sake of comparison, the conventional units are also shown here in Figures 10, 12 and 14. Table 8 summarizes the key design data. For a more detailed summary of unit performance data, see the Summary Sheets located in Appendix B.

TABLE 8. DESIGN DATA SUMMARY FOR LIMB UNITS

NOMINAL MW RATING	200	400	600
Gross MW	196	447	621
Steam Flows			
Superheat	1331	3034	4225
Reheat	1195	2700	3764
Superheater Outlet Pressure	2620	2620	2620
Furnace Width, ft.	37	58	64
Furnace Depth, ft	40	45	51
Furnace Height, ft.	137	152	181
No. of Burners	16	30	42
No. of Pulverizers	4	5	6
Pulverizer Size	MPS-67	MPS-89	MPS-89
Fuel Rates, 1000 lb/hr	232.8	529.7	730.0
Gross Efficiency, %	84.52	83.80	83.91
MCR Ca/S	3.3	3.4	3.4
Air Heaters			
Type	Twinflow	Twinflow	Twinflow
Quantity	1	1	2
Diameters, Meters (Overall/Primary Section)	12.5/6.7	19/10	14/7.5

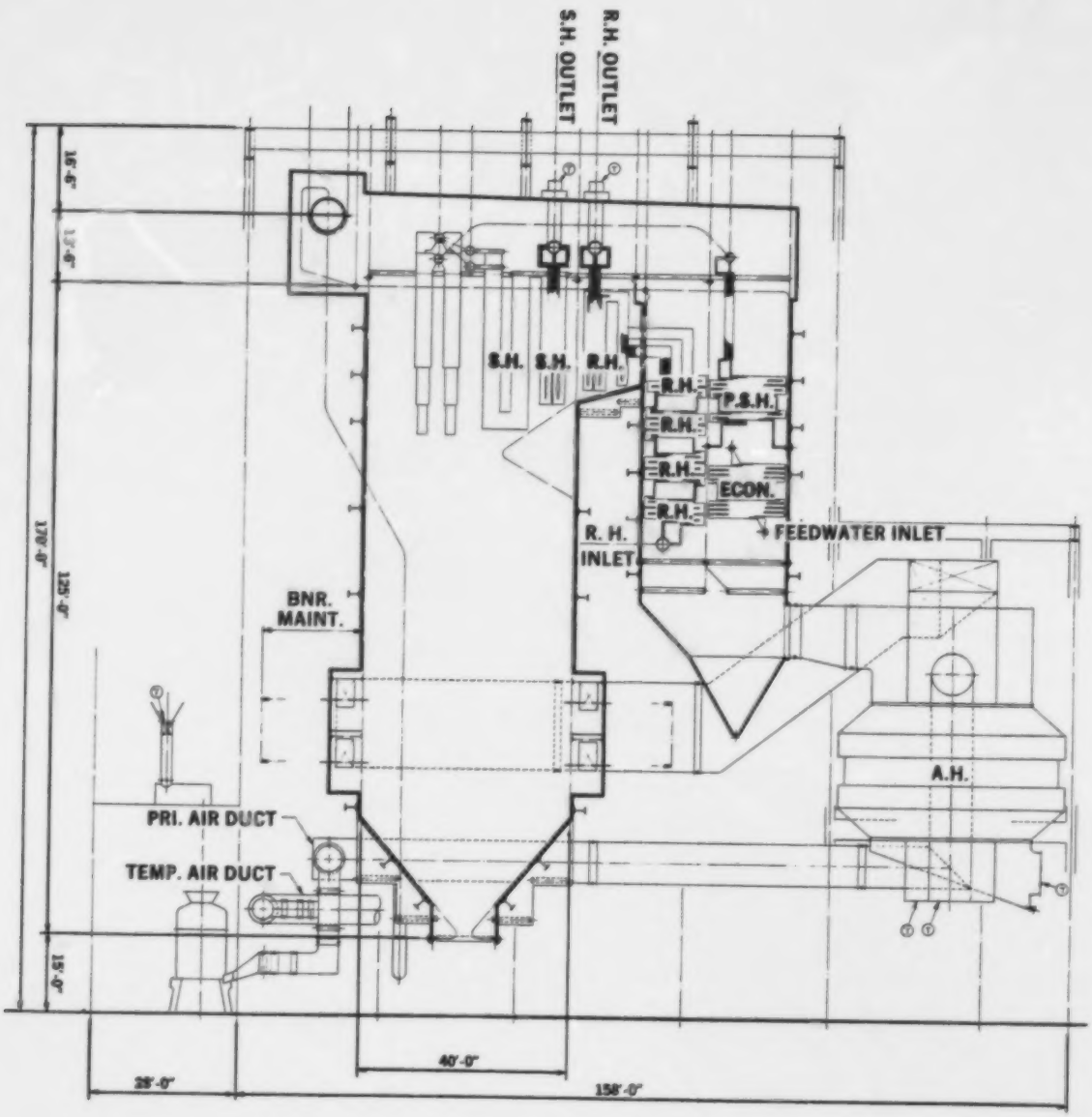


FIGURE 10. 200 MW CONVENTIONAL UNIT

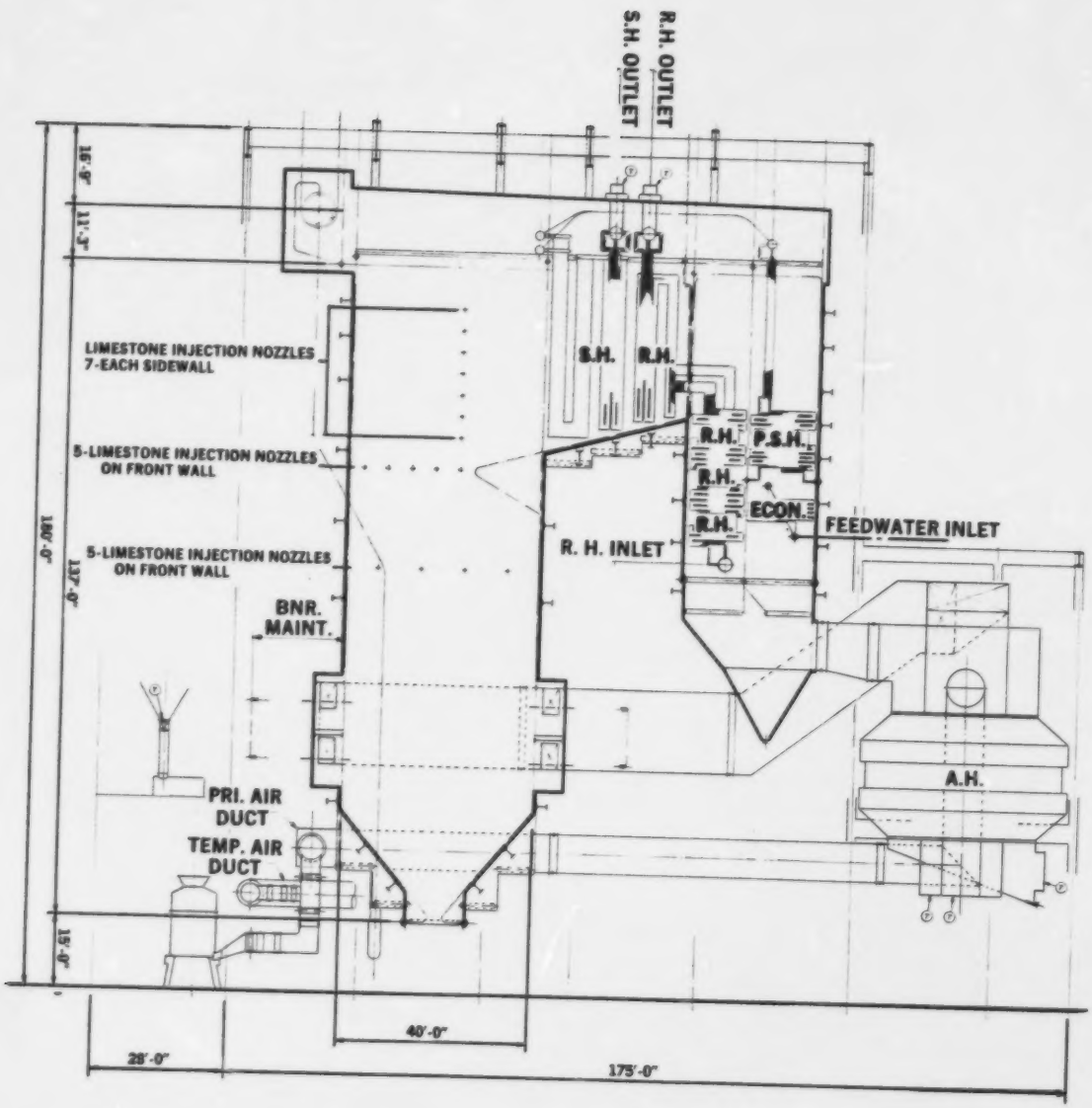


FIGURE 11. 200 MW LIMB UNIT

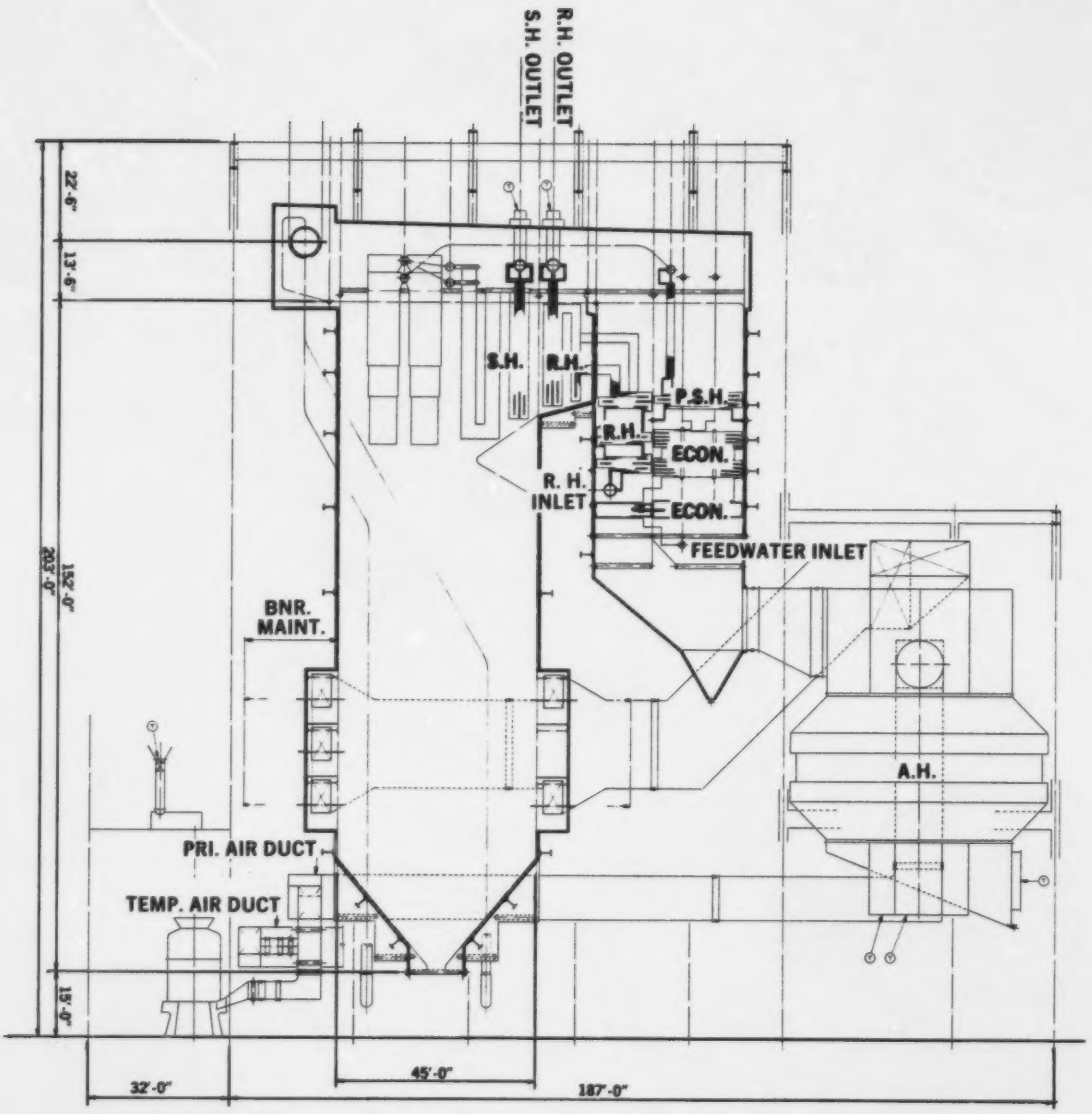


FIGURE 12. 400 MW CONVENTIONAL UNIT

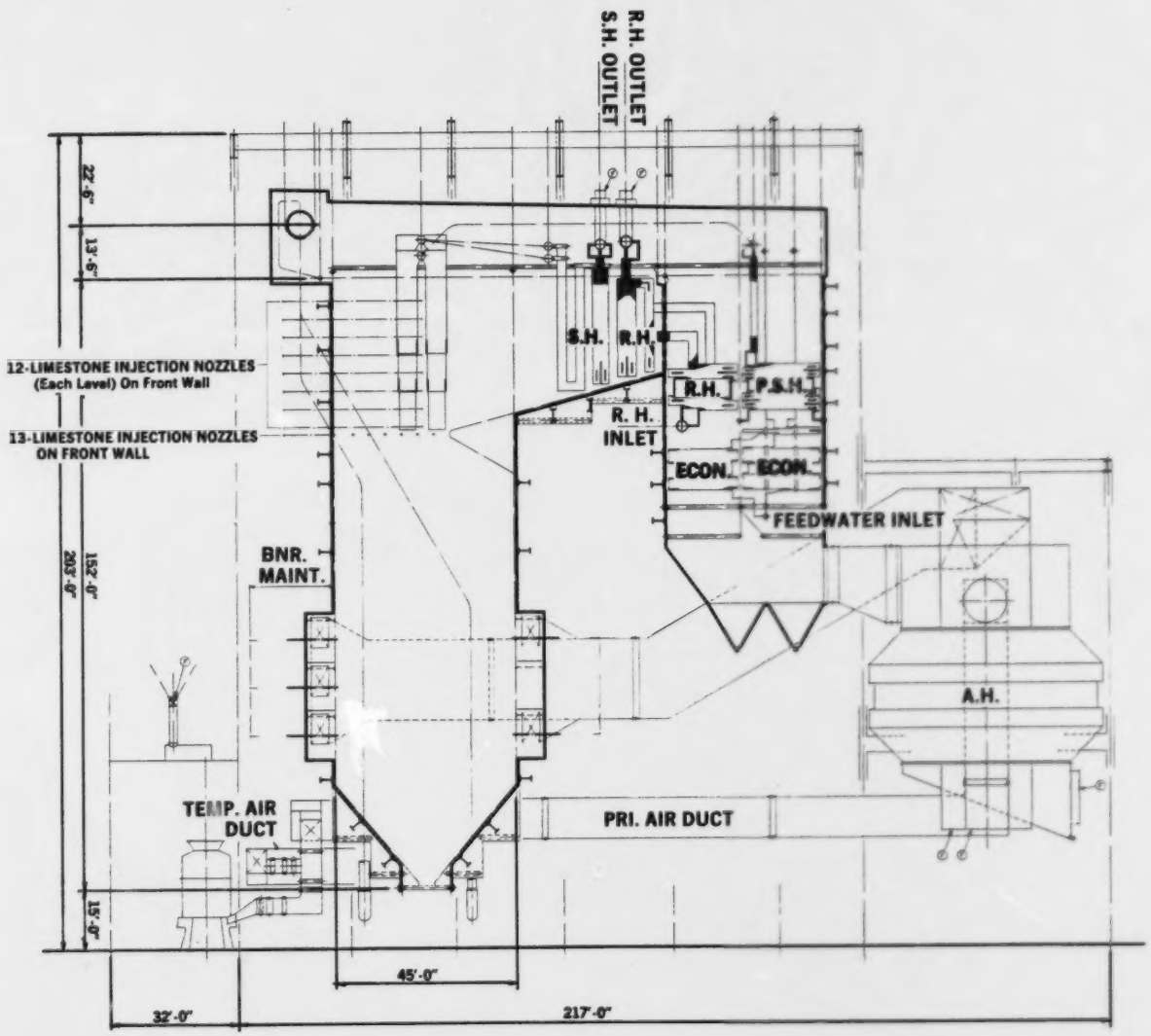


FIGURE 13. 400 MW LIMB UNIT

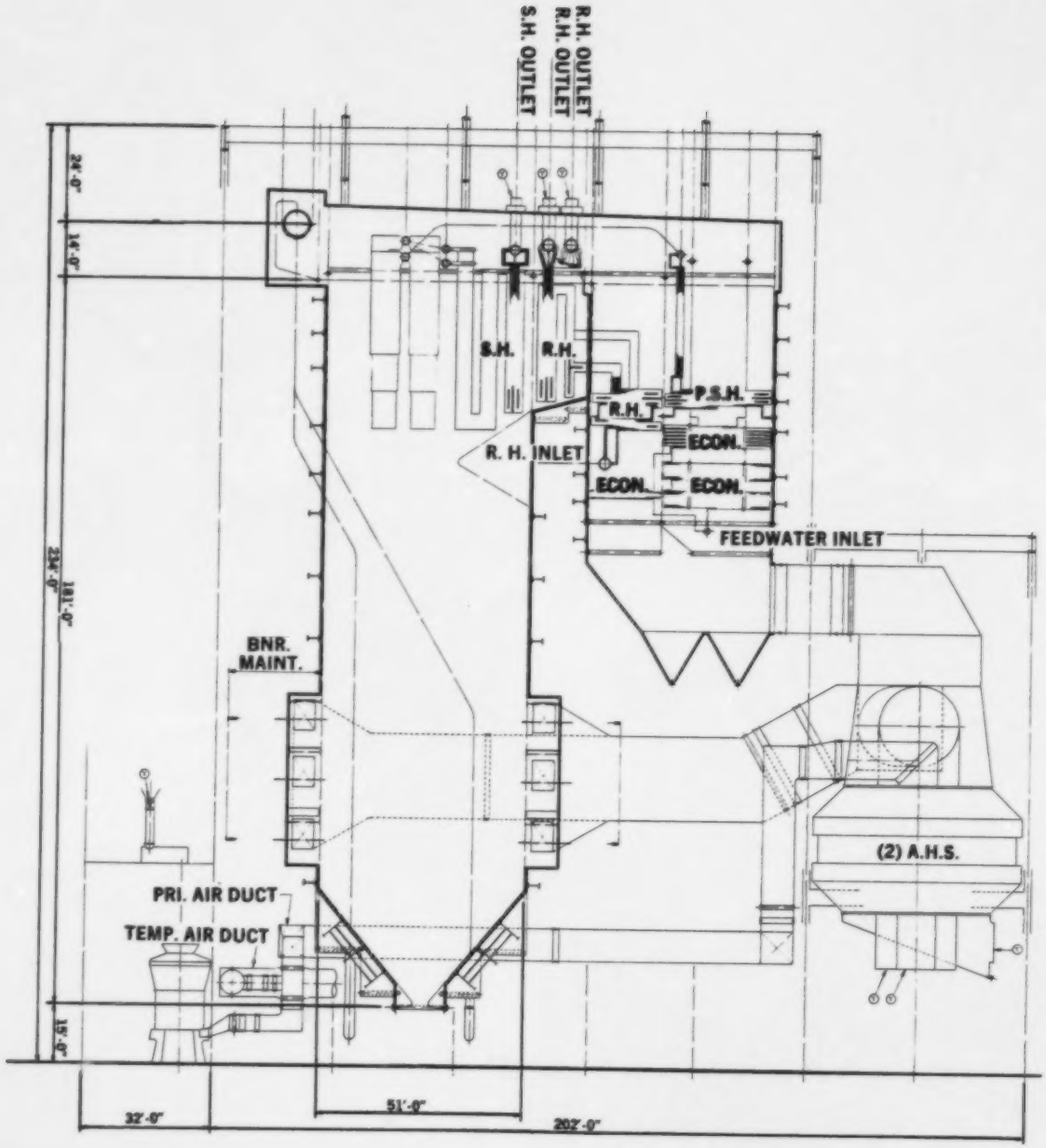


FIGURE 14. 600 MW CONVENTIONAL UNIT

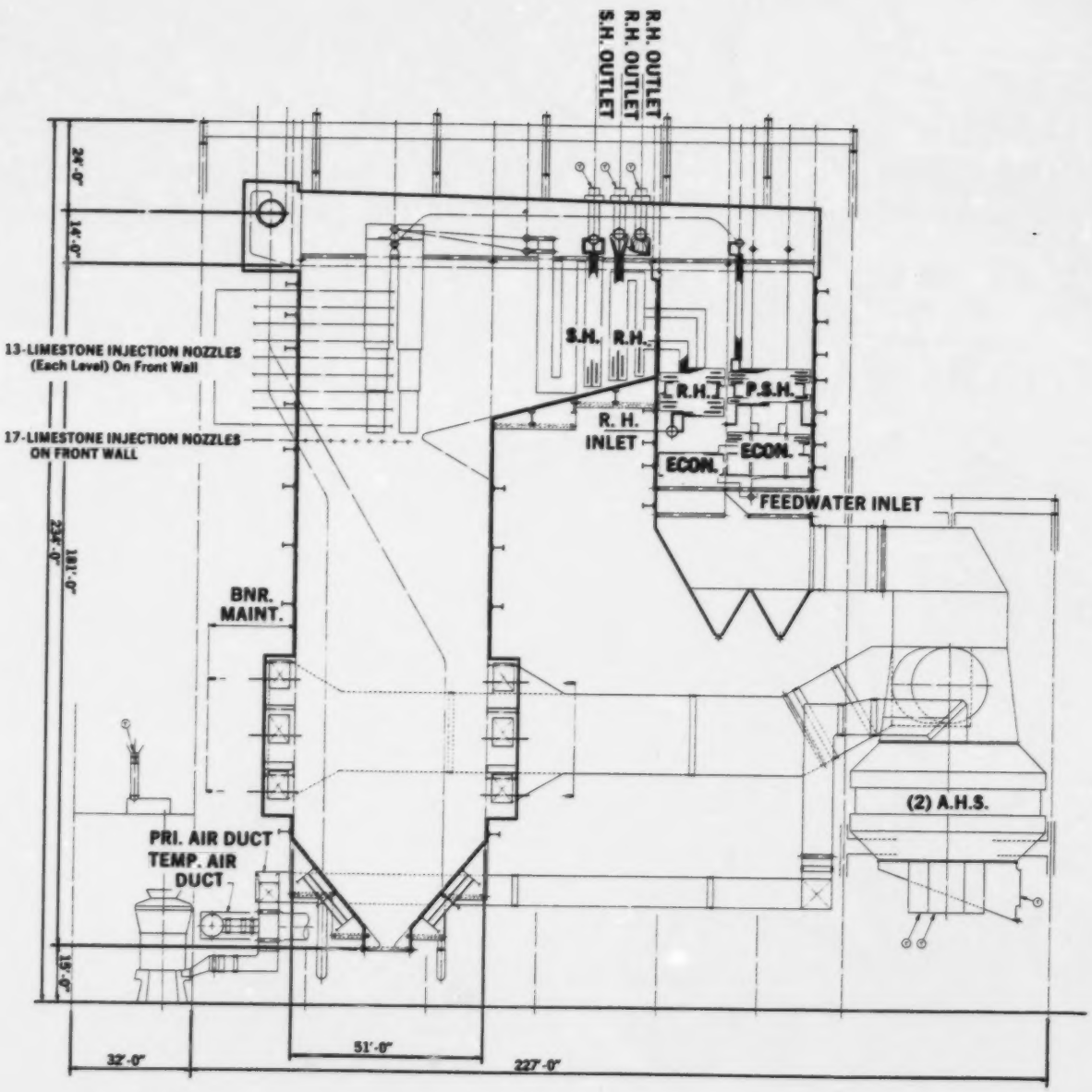


FIGURE 15. 600 MW LIMB UNIT

COST DIFFERENTIALS

In order to evaluate the economics of the LIMB process, it was necessary to determine the cost differential between the conventional units and the corresponding LIMB units. Furthermore, in order to determine the "optimum" Ca/S ratio for each unit size, it was necessary to approximate a functional relationship between cost and Ca/S ratio. The procedures used to develop these cost relationships and the results of the work are presented in this section.

The first step was to establish the baseline cost of the conventional units using standard B&W estimating procedures and data. The scope of supply included in these baseline cost estimates are summarized in Table 9.

TABLE 9. BASE SCOPE OF SUPPLY USED FOR CONVENTIONAL BOILER COST ESTIMATE

1. Pressure parts (as depicted on the boiler arrangement drawings)
2. Support hangers
3. Flues and ducts from boiler to air heater
4. Air heater
5. Burners, lighters, and lighter controls.
6. Feeders and feeder drives
7. Raw coal pipe from feeder to pulverizer
8. Pulverizers (less drives)
9. Coal-air piping
10. Sootblowers
11. Structural Steel
12. Insulation & Lagging
13. Blowoff and drain valves
14. Safety valves
15. Feedwater valves
16. Water gauges
17. Superheater and reheater thermocouples

With baseline costs established, a comparison was made between the conventional unit and its counterpart LIMB unit. This comparison identified those areas which were different and quantified the magnitude of the differences. A summary of the major areas of change is presented in Table 10. With the changes identified and quantified, standard estimating data and procedures were again used to determine the differential cost between the conventional and LIMB units. The results of this analysis are presented in Table 11. Figure 16 illustrates the distribution of cost differentials between various major components.

TABLE 10. MAJOR AREAS OF COST CHANGE BETWEEN CONVENTIONAL AND LIMB BOILERS

1. Water cooled injection lances (required for 400 MW and 600 MW LIMB units)
2. Wall openings for furnace wall mounted injectors
3. Furnace wall mounted injectors
4. Heating surface modifications
5. Structural steel modifications (including support hangers)
6. Flue and duct work

The preceding analysis provided a single data point for each unit size, i.e. a cost differential for a specific Ca/S ratio was quantified. However, in order to determine the "optimum" Ca/S ratio, a functional relationship between Ca/S ratio and cost is required. The ideal way to develop this function would include designing a number of units, each with a different Ca/S ratio. Differential costs could then be established at each Ca/S ratio, the resulting data points plotted, and an equation developed. This type of rigorous analysis was beyond the scope of this study. As a result, it was necessary to approximate a functional relationship between Ca/S ratio and cost. This approximation was developed by recognizing that with a sufficiently high Ca/S ratio, it is theoretically possible to achieve 70% sulfur capture in a conventional unit.

Table 5 on page 22 lists the Ca/S ratio required for 70% capture in the conventional units. By presuming conventional units can be converted to LIMB units with no boiler modifications other than adding injection nozzles, another data point can be established. With two data points now available (see Table 11.) for each unit size, we can develop an approximate cost function relating Ca/S to differential costs ($/KW). These functions are shown graphically in Figure 17.

TABLE 11. COST DIFFERENTIALS ($/KW)

	CONVENTIONAL	LIMB UNITS	
	UNIT COST	Ca/S	COST
200 MW	Base	3.30	$13.20/KW
(196 Gross)		4.25	$ 1.26/KW*
400 MW	Base	3.4	$8.39/KW
(447 Gross)		4.7	$1.07/KW*
600 MW	Base	3.4	$7.01/KW
(621 Gross)		4.8	$1.06/KW*

*Values represent costs for sorbent injectors only

Since only two points are available, the resulting function is linear. However, since heat transfer mechanisms are affected by changing the Ca/S ratio (higher quench rates and longer residence times require larger cavities which result in lower gas temperatures entering the secondary superheater sections) it is probable that the true function is exponential. The inaccuracy introduced by using the linear approximation will have an impact on the absolute values determined in subsequent analysis, but should not alter the trends identified.

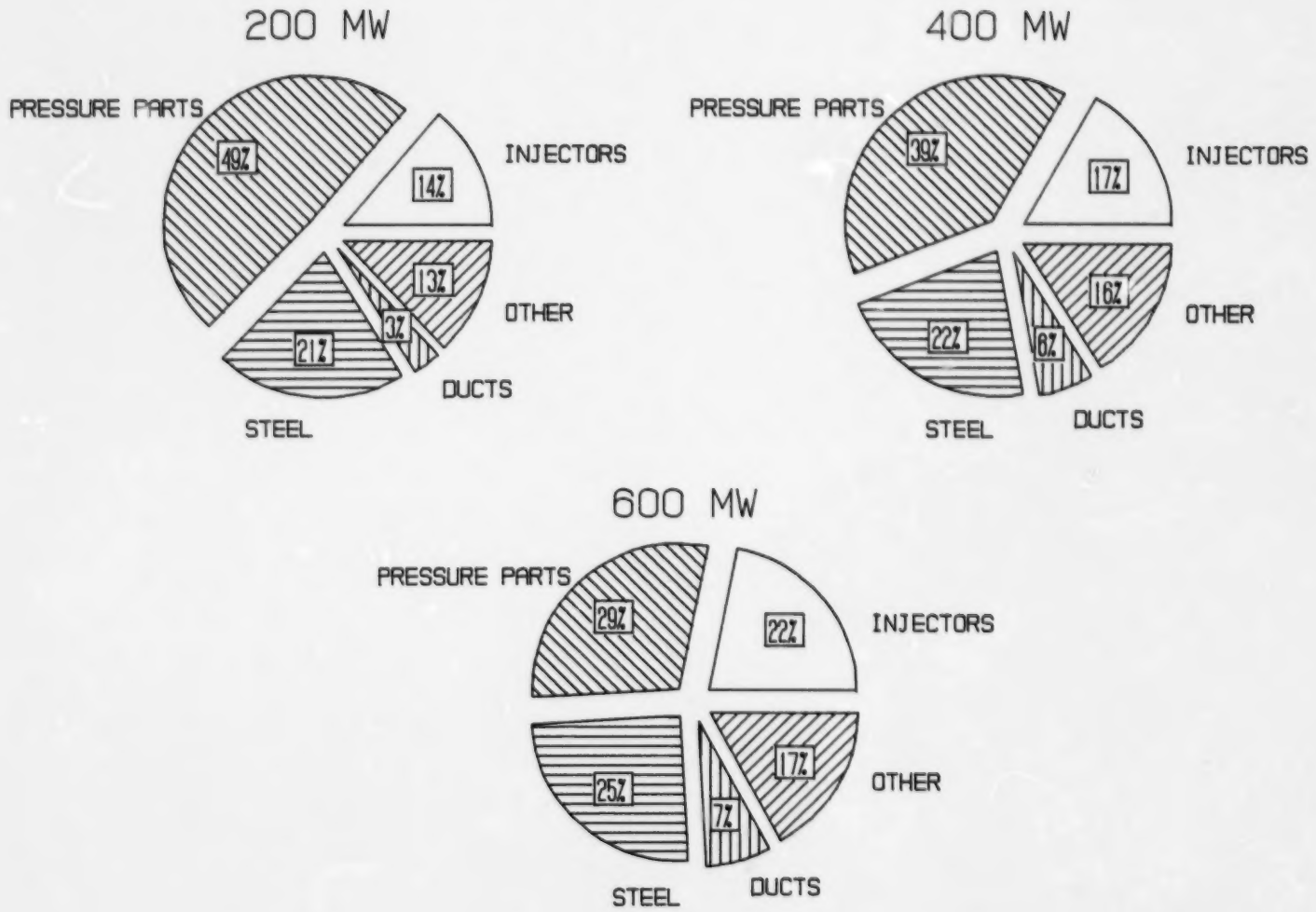


FIGURE 16. DISTRIBUTION OF COST DIFFERENTIALS

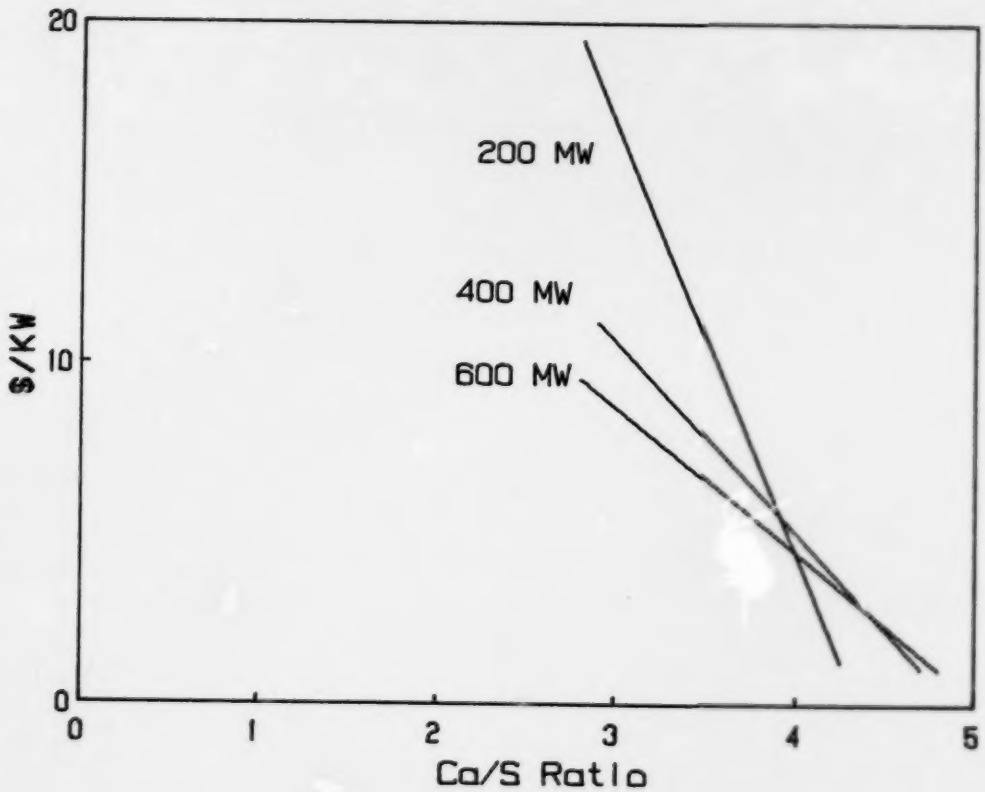


FIGURE 17. COST DIFFERENTIALS VS. Ca/S RATIO

ECONOMIC ANALYSIS

This section presents the results of the economic analysis performed during the study. This analysis used the capital cost functions developed in the previous section combined with operating costs to determine trends and to establish the existence of an optimum Ca/S ratio. These trends only reflect capital cost differences associated with modifying the boiler. Capital costs for the required sorbent preparation and transport system and the costs associated with changes to auxiliary equipment (such as fans, precipitators, etc.) were not included in the analysis.

Methodology

The key economic parameter used for analysis was the "30 year levelized cost effectiveness of SO_2 removed ($/TON)". This parameter combines levelized capital and operating costs into a single value.

The first part of the economic analysis was to establish the trend of this value as a function of plant size and of Ca/S ratio. This was accomplished by calculating the "30 year levelized cost effectiveness of SO_2 removed" for a range of Ca/S ratios and then plotting the results as a function of both plant size and Ca/S ratio.

The second part of the analysis was to establish an "optimum" Ca/S ratio at each plant size. This "optimum" point was initially defined as the Ca/S ratio that yielded the lowest 30 year levelized cost effectiveness. However, when it became apparent that the curves did not have a minimum point, it was necessary to establish another constraint. This proved to be the thermodynamic constraints of the boiler. Since the residence time cavity is not isothermal, increasing its size yields lower temperatures entering the convection heating surface. Below a certain point there is no longer adequate gas temperature to complete the required heat transfer to surfaces downstream of the cavity. The "optimum" point could then be redefined as the lowest Ca/S ratio thermodynamically achievable given a non-isothermal residence time cavity.

The 30 year levelized cost effectiveness was calculated using a computer program provided by the EPA entitled LIMBCOST. This program utilizes inputs which can be broken down into three basic categories: 1) process data; 2) capital cost data; and 3) economic data and assumptions.

The required process data input consisted principally of plant heat rates corresponding to the Ca/S ratios being considered. These heat rates are used by LIMBCOST to calculate fuel rates and sorbent flows. Therefore, it was necessary to input a heat rate which when used by LIMBCOST would yield the same fuel rates as those used in the functional calculations. This was done by simply dividing the fuel input used in the functional calculations by the MW rating. These heat rates included terms to account for the losses associated with the injection lances and the additional excess air introduced to inject the sorbent.

Capital cost data was obtained by using the cost vs. Ca/S ratio curves developed in the previous section. For each Ca/S ratio being evaluated, a value for "other modifications" was input. This value included all the costs resulting from the boiler modifications necessary to make the unit "LIMB friendly". Because these costs were combined into one value, all other "Process Capital" inputs were set to zero.

Most of the economic data used (ie. interest rates, construction period, labor costs, etc.) were either default values or recommendations from the EPA project officer. These values are given in Tables 12 and 13. It was beyond the scope of this investigation to verify any economic data not directly associated with the required boiler modifications. Major values used are also included in the representative LIMBCOST outputs presented in Tables 15 thru 20 at the end of this section. While most of the economic inputs are self-explanatory, two do require some clarification: Sorbent costs and fuel costs.

TABLE 12. MAJOR ECONOMIC PREMISES FOR COST OF CAPITOL

Base year for cost comparison	1985
Book life, years	30
Tax life, years	15
Inflation rate, %/yr	8.5
Debt/equity ratio	50/50
Debt cost, %/yr	11.0
Preferred stock ratio,%	15
Preferred cost, %/yr	11.5
Common stock ratio, %	35
Common stock cost, %/yr	15.3
Weighted cost of capitol	12.5
Federal plus state income tax rate, %	50
Property taxes and insurance, %/yr	2
Investment tax credit, %	10
Levelized carrying charge rate, %	16.01

TABLE 13. MAJOR ECONOMIC PREMISES FOR OPERATING AND MAINTENANCE COSTS

Base year for cost comparison	1985
Unit capacity factor, %	62.8
Book life, years	30
Tax life, years	15
Levelizing factor	2.314
Waste disposal cost, $/ton	7.66
Operating manhours/year	17,520
Average labor rate, $/hr	23.37
Sorbent cost, $/ton	50.00
Water, $/1000 gal.	0.77
Process steam, $/1000 lb	4.84
In-plant power, mills/kWh	58
Coal cost, $/106 Btu	2.61

Sorbent costs were fixed at \$50/ton for $Ca(OH)_2$. This was based on input from investigators involved with the LIMB Demonstration Project (EPA Contract No. 68-02-4000. Fuel costs were set at the program default value of \$2.61/million Btu. There is some question about the validity of this value, for example according to TAG, the 1985 delivered sub-bituminous fuel costs are \$1.50 million Btu. However, the differential fuel cost caused by the LIMB process is so overshadowed by the sorbent costs that the results of the analysis are insensitive to fuel costs.

Two minor modifications to LIMBCOST were required. First it was necessary to zero out the costs calculated by the program for the sorbent preparation and injection system. This was done because costing of the sorbent preparation system was beyond the scope of this study and the injection nozzle costs are included as part of the differential boiler costs. Secondly, the differential fuel costs calculated by the program accounted only for the sorbent heats of calcination and sulfation and not for the lance losses and excess air losses. A program modification was made to account for these losses and thus obtain a more accurate differential fuel rate.

Ideally, the thermodynamic lower limit of Ca/S ratio could be obtained by designing a series of units with ever decreasing temperatures leaving the residence time cavity. Since the scope of this study precluded such an analysis, it was necessary to approximate this value. This was done with acceptable accuracy by first doing a heat and mass balance around the components downstream of the cavity to determine the minimum acceptable temperature leaving the cavity. Then, recognizing that the temperature drop across the cavity and the required Ca/S ratio are both functions of the cavity size, it was possible to establish a relationship between the Ca/S ratio and the gas temperature leaving the cavity.

Results

Figures 18 and 19 are plots of capital cost differentials and SO_2 removal cost effectiveness as a function of MW rating at Ca/S ratios of 3.4 and 2.8 respectively. The LIMBCOST runs used to calculate SO_2 removal cost effectiveness are presented in Tables 15 thru 20 at the end of this section. The curves show the expected trends of improved capital costs and cost effectiveness with increasing unit size.

Figure 20 shows SO_2 removal cost effectiveness as a function of Ca/S ratio. As previously mentioned, the dominance of the sorbent costs resulted in a trend towards improved cost effectiveness with lower Ca/S ratio at any given unit size. The location of the 200 MW curve relative to the 400 MW and 600 MW is explained by the fact that wall nozzles were used for sorbent injection instead of lances. As a result, the efficiencies of the 200 MW LIMB units are higher than the 400 MW and 600 MW LIMB units. This means proportionately less sorbent flow for a given Ca/S ratio. Less sorbent flow gives lower sorbent costs and since sorbent costs dominate the function, the 200 MW curve seems to break away from the general trend of cost effectiveness vs. MW rating.

Table 14 lists the "optimum" Ca/S ratio for each unit size along with the corresponding cost effectiveness and capital cost differential. The conclusions to be drawn from this analysis are: 1) lower Ca/S ratios result in a more cost effective process; 2) at or near the optimum Ca/S ratio cost effectiveness improves with increasing unit size and 3) the "optimum" Ca/S ratio is set by thermodynamic constraints.

TABLE 14. OPTIMUM Ca/S RATIOS

	Optimum Ca/S	Cost Differential ($/KW)	Cost Effectiveness ($/TON SO_2)
200 MW	2.8	$19.48/KW	$1410.49/TON
400 MW	2.9	$11.20/KW	$1319.12/TON
600 MW	2.8	$ 9.55/KW	$1200.28/TON

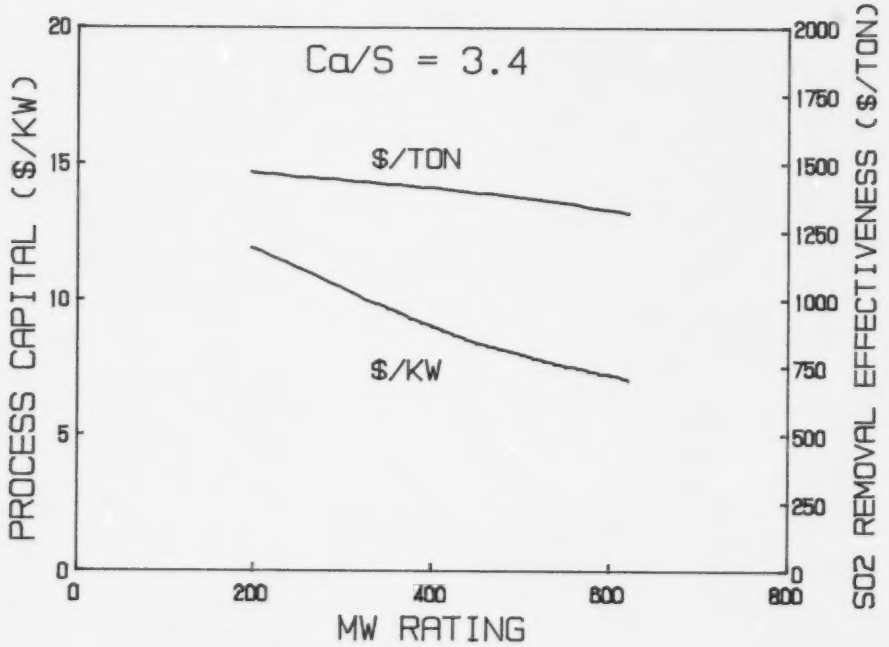


FIGURE 18. CAPITAL COST DIFFERENTIAL AND SO_2 REMOVAL EFFECTIVENESS VS. MW'S AT 3.4 Ca/S

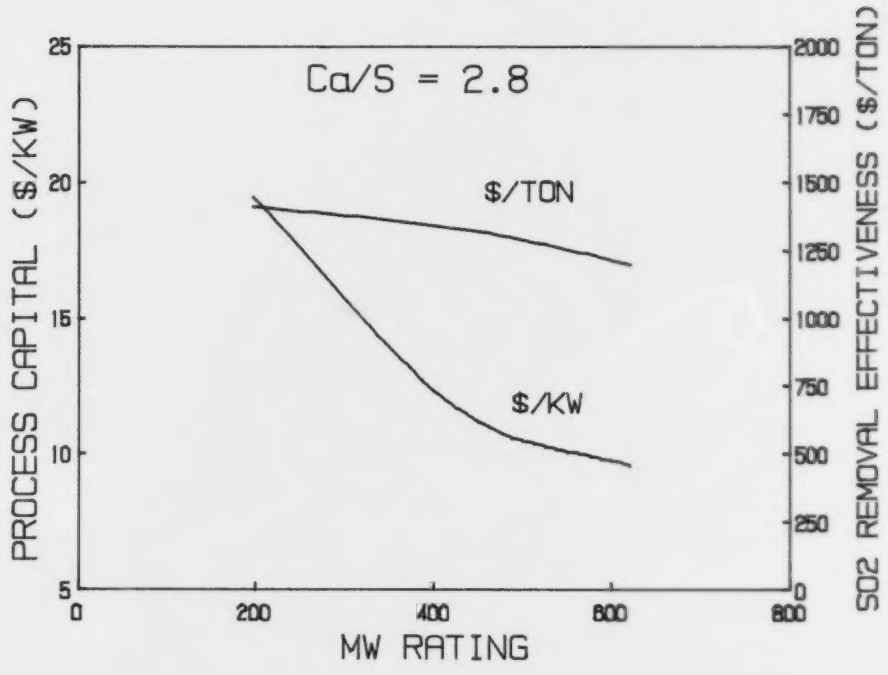


FIGURE 19. CAPITAL COST DIFFERENTIAL AND SO_2 REMOVAL EFFECTIVENESS VS. MW'S AT 2.8 Ca/S

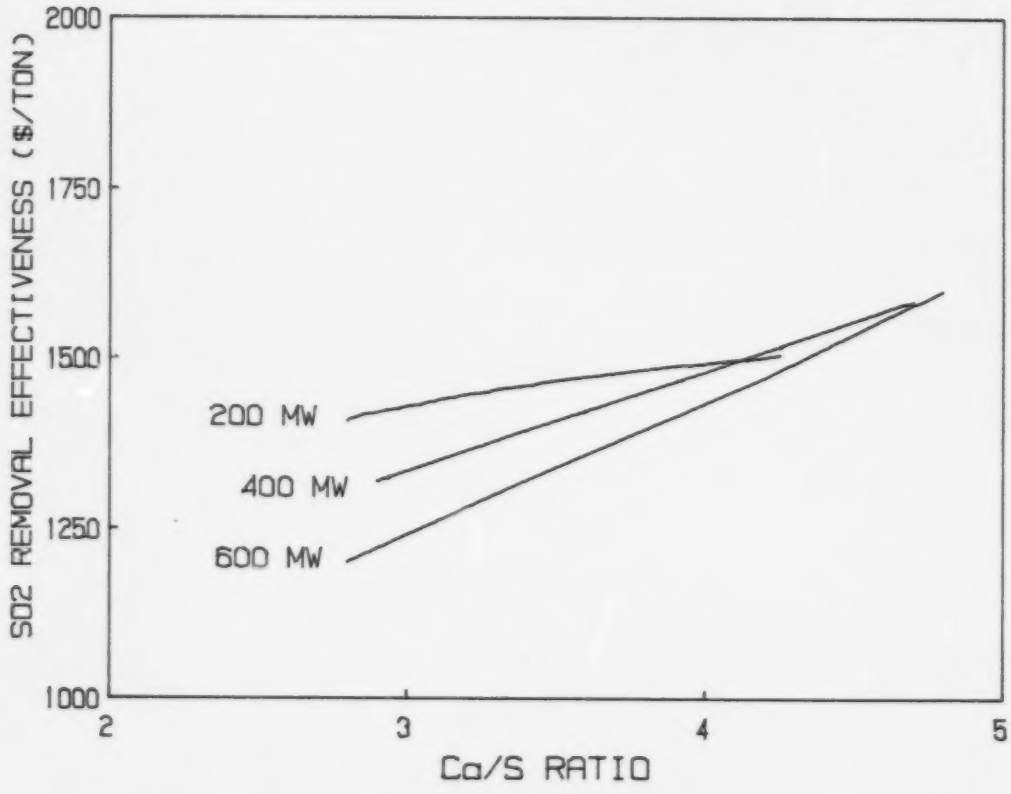


FIGURE 20. SO_2 REMOVAL EFFECTIVENESS VS. Ca/S RATIO

TABLE 15. LIMBCOST OUTPUT FOR 200 MW UNIT AT 3.4 Ca/S RATIO

LIMB ECONOMIC ANALYSIS

(Dec 1985 dollars)

BOILER SIZE, MWe	196
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9530.74
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	0
CALCIUM TO SULFUR RATIO	3.4
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	4452.079
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	15

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	2341095	11.94
PROCESS CAPITAL		(PC)	2341095	11.94
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$2341095			
GENERAL FACILITIES	(10.0% of PC)		234109	1.19
ENGINEERING/HOME OFFICE	(12.0% of PC)		280931	1.43
PROJECT CONTINGENCY	(20.0% of PC)		468219	2.39
PROCESS CONTINGENCY	(10.0% of PC)		234109	1.19
SALES TAX	(6.0% of PC)		140466	0.72
TOTAL PLANT COST (Dec '85 $)			3710635	18.93
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			3777427	19.27
ROYALTY ALLOWANCE			11705	0.06
PREPRODUCTION COSTS			1250099	6.38
INVENTORY CAPITAL			335101	1.71
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			5362627	27.36

(CONTINUED)

TABLE 15 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	2.09	
MAINTENANCE LABOR	37458	0.19	
MAINTENANCE MATERIAL	56186	0.29	
ADMINISTRATIVE AND SUPPORT LABOR	134070	0.68	
TOTAL O+M First Year	637156	3.25	
FIXED O+M First Year	414152	2.11	
VARIABLE O+M First Year	223005	0.20	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	1289156	1.16
WASTE DISPOSAL	193050	0.17
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	323647	0.29
TOTAL CONSUMABLES (excluding fuel)	1805853	1.62

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	17739	0.02

BY-PRODUCT CREDIT (First year-Dec '85 dollars)	$0	$0.00 mills/KW-hr
CARRYING CHARGES (First year - Dec '85 dollars)	$821018	$4.19 / KW-yr
BUSBAR COST OF POWER (First year-Dec '85 dollars)	$3281765	2.94 mills/KW-hr
FIRST YEAR COST EFFECTIVENESS SO2 REMOVED	$3281765	$737.13 / ton

(CONTINUED)

TABLE 15 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$958347	$4.89 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$516033	0.46 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$4178743	3.74 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$45570	0.04 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$0	$0.00 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$821018	$ 4.19 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$6519710	5.84 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$6519710	$1464.42 / ton

TABLE 16. LIMBCOST OUTPUT FOR 200 MW UNIT AT 2.8 Ca/S RATIO

LIMB ECONOMIC ANALYSIS

(Dec 1985 dollars)

BOILER SIZE, MWe	196
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9529.821
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	1
CALCIUM TO SULFUR RATIO	2.8
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	4449.308
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	15

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	3818926	19.48
PROCESS CAPITAL		(PC)	3818926	19.48
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$3818926			
GENERAL FACILITIES		(10.0% of PC)	381893	1.95
ENGINEERING/HOME OFFICE		(12.0% of PC)	458271	2.34
PROJECT CONTINGENCY		(20.0% of PC)	763785	3.90
PROCESS CONTINGENCY		(10.0% of PC)	381893	1.95
SALES TAX		(6.0% of PC)	229136	1.17
TOTAL PLANT COST (Dec '85 $)			6052998	30.88
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			6161952	31.44
ROYALTY ALLOWANCE			19095	0.10
PREPRODUCTION COSTS			1270079	6.48
INVENTORY CAPITAL			272855	1.39
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			7704886	39.31

(CONTINUED)

TABLE 16 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	2.09	
MAINTENANCE LABOR	61103	0.31	
MAINTENANCE MATERIAL	91654	0.47	
ADMINISTRATIVE AND SUPPORT LABOR	141164	0.72	
TOTAL O+M First Year	703363	3.59	
FIXED O+M First Year	457186	2.33	
VARIABLE O+M First Year	246177	0.22	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	1060997	0.95
WASTE DISPOSAL	166349	0.15
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	323647	0.29
TOTAL CONSUMABLES (excluding fuel)	1550993	1.39

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	3136	0.00

BY-PRODUCT CREDIT (First year-Dec '85 dollars)	$55556	$0.05 mills/KW-hr
CARRYING CHARGES (First year - Dec '85 dollars)	$1179618	$6.02 / KW-yr
BUSBAR COST OF POWER (First year-Dec '85 dollars)	$3381554	3.03 mills/KW-hr
FIRST YEAR COST EFFECTIVENESS SO2 REMOVED	$3381554	$760.02 / ton

(CONTINUED)

TABLE 16 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$1057928	$5.40 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$569654	0.51 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$3588998	3.22 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$8057	0.01 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$128557	$0.12 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$1179618	$ 6.02 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$6275698	5.62 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$6275698	$1410.49 / ton

TABLE 17. LIMBCOST OUTPUT FOR 400 MW UNIT AT 3.4 Ca/S RATIO

LIMB ECONOMIC ANALYSIS

(Dec 1985 dollars)

BOILER SIZE, MWe	447
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9497.441
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	0
CALCIUM TO SULFUR RATIO	3.4
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	10117.99
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	15

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	3749999	8.39
PROCESS CAPITAL		(PC)	3749999	8.39
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$3749999			
GENERAL FACILITIES		(10.0% of PC)	375000	0.84
ENGINEERING/HOME OFFICE		(12.0% of PC)	450000	1.01
PROJECT CONTINGENCY		(20.0% of PC)	750000	1.68
PROCESS CONTINGENCY		(10.0% of PC)	375000	0.84
SALES TAX		(6.0% of PC)	225000	0.50
TOTAL PLANT COST (Dec '85 $)			5943748	13.30
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			6050736	13.54
ROYALTY ALLOWANCE			18750	0.04
PREPRODUCTION COSTS			2726368	6.10
INVENTORY CAPITAL			901190	2.02
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			9680293	21.66

(CONTINUED)

TABLE 17 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	0.92	
MAINTENANCE LABOR	60000	0.13	
MAINTENANCE MATERIAL	90000	0.20	
ADMINISTRATIVE AND SUPPORT LABOR	140833	0.32	
TOTAL O+M First Year	700275	1.57	
FIXED O+M First Year	455179	1.02	
VARIABLE O+M First Year	245096	0.10	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	2929793	1.15
WASTE DISPOSAL	438733	0.17
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	738113	0.29
TOTAL CONSUMABLES (excluding fuel)	4106639	1.61

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	584848	0.23

BY-PRODUCT CREDIT (First year-Dec '85 dollars)	$0	$0.00 mills/KW-hr
CARRYING CHARGES (First year - Dec '85 dollars)	$1482053	$3.32 / KW-yr
BUSBAR COST OF POWER (First year-Dec '85 dollars)	$6873815	2.70 mills/KW-hr
FIRST YEAR COST EFFECTIVENESS SO2 REMOVED	$6873815	$679.37 / ton

(CONTINUED)

TABLE 17 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$1053284	$2.36 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$567153	0.22 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$9502762	3.73 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$1502474	0.59 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$0	$0.00 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$1482053	$ 3.32 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$14107726	5.54 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$14107726	$1394.32 / ton

TABLE 18. LIMBCOST OUTPUT FOR 400 MW UNIT AT 2.9 Ca/S RATIO

LIMB ECONOMIC ANALYSIS

(Dec 1985 dollars)

BOILER SIZE, MWe	447
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9496.67
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	0
CALCIUM TO SULFUR RATIO	2.9
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	10112.74
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	15

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	5007691	11.20
PROCESS CAPITAL		(PC)	5007691	11.20
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$5007691			
GENERAL FACILITIES	(10.0% of PC)		500769	1.12
ENGINEERING/HOME OFFICE	(12.0% of PC)		600923	1.34
PROJECT CONTINGENCY	(20.0% of PC)		1001538	2.24
PROCESS CONTINGENCY	(10.0% of PC)		500769	1.12
SALES TAX	(6.0% of PC)		300461	0.67
TOTAL PLANT COST (Dec '85 $)			7937190	17.76
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			8080060	18.08
ROYALTY ALLOWANCE			25038	0.06
PREPRODUCTION COSTS			2710712	6.06
INVENTORY CAPITAL			783281	1.75
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			11574052	25.89

(CONTINUED)

TABLE 18 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	0.92	
MAINTENANCE LABOR	80123	0.18	
MAINTENANCE MATERIAL	120185	0.27	
ADMINISTRATIVE AND SUPPORT LABOR	146870	0.33	
TOTAL O+M First Year	756620	1.69	
FIXED O+M First Year	491803	1.10	
VARIABLE O+M First Year	264817	0.10	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	2497643	0.98
WASTE DISPOSAL	388160	0.15
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	738113	0.29
TOTAL CONSUMABLES (excluding fuel)	3623917	1.42

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	557152	0.22

BY-PRODUCT CREDIT (First year-Dec '85 dollars)	$0	$0.00 mills/KW-hr
CARRYING CHARGES (First year - Dec '85 dollars)	$1771987	$3.96 / KW-yr
BUSBAR COST OF POWER (First year-Dec '85 dollars)	$6709675	2.54 mills/KW-hr
FIRST YEAR COST EFFECTIVENESS SO2 REMOVED	$6709675	$663.49 / ton

(CONTINUED)

TABLE 18 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$1138032	$2.55 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$612786	0.24 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$8385742	3.29 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$1431322	0.56 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$0	$0.00 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$1771987	$ 3.96 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$13339870	5.24 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$13339870	$1319.12 / ton

TABLE 19. LIMBCOST OUTPUT FOR 600 MW UNIT AT 3.4 Ca/S RATIO

LIMB ECONOMIC ANALYSIS
(Dec 1985 collars)

BOILER SIZE, MWe	621
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9440.361
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	0
CALCIUM TO SULFUR RATIO	3.4
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	13972.06
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	15

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	4350000	7.00
PROCESS CAPITAL		(PC)	4350000	7.00
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$4350000			
GENERAL FACILITIES	(10.0% of PC)		435000	0.70
ENGINEERING/HOME OFFICE	(12.0% of PC)		522000	0.84
PROJECT CONTINGENCY	(20.0% of PC)		870000	1.40
PROCESS CONTINGENCY	(10.0% of PC)		435000	0.70
SALES TAX	(6.0% of PC)		261000	0.42
TOTAL PLANT COST (Dec '85 $)			6894750	11.10
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			7018856	11.30
ROYALTY ALLOWANCE			21750	0.04
PREPRODUCTION COSTS			3721704	5.99
INVENTORY CAPITAL			1218029	1.96
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			11958589	19.26

(CONTINUED)

TABLE 19 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	0.66	
MAINTENANCE LABOR	69600	0.11	
MAINTENANCE MATERIAL	104400	0.17	
ADMINISTRATIVE AND SUPPORT LABOR	143713	0.23	
TOTAL O+M First Year	727155	1.17	
FIXED O+M First Year	472651	0.76	
VARIABLE O+M First Year	254504	0.07	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	4045786	1.14
WASTE DISPOSAL	605852	0.17
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	1025432	0.29
TOTAL CONSUMABLES (excluding fuel)	5677071	1.61

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	704527	0.20

BY-PRODUCT CREDIT (First year-Dec '85 dollars) $0 $0.00 mills/KW-hr

CARRYING CHARGES (First year - Dec '85 dollars) $1830860 $2.95 / KW-yr

BUSBAR COST OF POWER (First year-Dec '85 dollars) $8939613 2.53 mills/KW-hr

FIRST YEAR COST EFFECTIVENESS SO2 REMOVED $8939613 $639.82 / ton

(CONTINUED)

TABLE 19 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$1093714	$1.76 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$588923	0.17 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$13136741	3.72 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$1809931	0.51 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$0	$0.00 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$1830860	$ 2.95 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$18460168	5.22 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$18460168	$1321.22 / ton

TABLE 20. LIMBCOST OUTPUT FOR 600 MW UNIT AT 2.8 Ca/S RATIO

LIMB ECONOMIC ANALYSIS

(Dec 1985 dollars)

BOILER SIZE, MWe	621
FIRING METHOD, (1 = wall, 2 = tangential)	1
STATUS (1 = Retrofit, 2 = New)	2
NET PLANT HEAT RATE, Btu/KWhr	9439.43
CAPACITY FACTOR	.65
COAL HIGH HEATING VALUE, Btu/lb	8020
COAL SULFUR CONTENT, %	.48
COAL ASH CONTENT, %	6.4
SORBENT (1=CaCO3, 2=Ca(OH)2, 3=CaO, 4=CaMg(CO3)2, 5=CaMg(OH)4)	2
SORBENT COST, $/ton	50
BY-PRODUCT CREDIT, $/ton	0
CALCIUM TO SULFUR RATIO	2.8
SO2 CONTROL LEVEL, %	70
SO2 EMISSIONS LEVEL, lb/MBtu	0.36
SO2 REMOVED, tons / year	13963.33
PARTICULATE EMISSIONS LEVEL, lb/MBtu	.03
NOX EMISSIONS LEVEL, lb/MBtu	.4
WASTE DISPOSAL (1=Dry, 2=Sludge)	1
WASTE DISPOSAL COST, $ / ton	7.66
NUMBER OF OPERATING JOBS	2
AVERAGE LABOR RATE, $ / hr	23.37
BOOK LIFE, years	30
TAX LIFE, years	5

COST SUMMARY

CAPITAL INVESTMENT			$	$/KW
PROCESS CAPITAL		(PC)	5933571	9.55
PROCESS CAPITAL		(PC)	5933571	9.55
INJECTION SYSTEM	$0			
INJECTION SYSTEM	$0			
LOW NOX BURNERS	$0	(@ 0.00 /KW)		
ECONOMIZER MODS	$0	(@ 0.00 /KW)		
SOOTBLOWER UPGRD	$0	(@ 0.00 /KW)		
ESP UPGRADES	$0			
SO3 CONDITIONING	$0	(@ 0.00 /KW)		
OTHER MODS	$5933571			
GENERAL FACILITIES	(10.0% of PC)		593357	0.96
ENGINEERING/HOME OFFICE	(12.0% of PC)		712029	1.15
PROJECT CONTINGENCY	(20.0% of PC)		1186714	1.91
PROCESS CONTINGENCY	(10.0% of PC)		593357	0.96
SALES TAX	(6.0% of PC)		356014	0.57
TOTAL PLANT COST (Dec '85 $)			9404711	15.14
TOTAL PLANT INVESTMENT (Jan 1986 start-up)			9573996	15.42
ROYALTY ALLOWANCE			29668	0.05
PREPRODUCTION COSTS			3674432	5.92
INVENTORY CAPITAL			1022659	1.65
INITIAL CATALYST			0	0.00
LAND			0	0.00
TOTAL CAPITAL REQUIREMENT (Jan 86)			14271086	22.98

(CONTINUED)

TABLE 20 (CONT.)

OPERATING AND MAINTENANCE COSTS (First year - Dec '85 dollars)

	$	$/KW-YR	
OPERATING LABOR	409442	0.66	
MAINTENANCE LABOR	94937	0.15	
MAINTENANCE MATERIAL	142406	0.23	
ADMINISTRATIVE AND SUPPORT LABOR	151314	0.24	
TOTAL O+M First Year	798099	1.29	
FIXED O+M First Year	518764	0.84	
VARIABLE O+M First Year	279335	0.08	mills/KW-hr

CONSUMABLES OPERATING COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
SORBENT	3329743	0.94
WASTE DISPOSAL	522057	0.15
WATER	0	0.00
SO3	0	0.00
PROCESS STEAM	0	0.00
IN-PLANT POWER	1025432	0.29
TOTAL CONSUMABLES (excluding fuel)	4877233	1.38

INCREMENTAL FUEL COSTS (First year - Dec '85 dollars)

	$	mills/KW-hr
COAL	658625	0.19

BY-PRODUCT CREDIT (First year-Dec '85 dollars) $0 $0.00 mills/KW-hr

CARRYING CHARGES (First year - Dec '85 collars) $1935159 $3.12 / KW-yr

BUSBAR COST OF POWER (First year-Dec '85 dollars) $8269116 2.34 mills/KW-hr

FIRST YEAR COST EFFECTIVENESS SO2 REMOVED $8269116 $592.20 / ton

(CONTINUED)

TABLE 20 (CONCLUDED)

30 - YEAR LEVELIZED O+M COSTS		
30 - YEAR LEVELIZED FIXED O+M	$1200421	$1.93 /KW-yr
30 - YEAR LEVELIZED VARIABLE O+M	$846381	0.18 mills/KW-hr
30 - YEAR LEVELIZED CONSUMABLES O+M	$11285915	3.19 mills/KW-hr
30 - YEAR LEVELIZED FUEL	$1692008	0.48 mills/KW-hr
30 - YEAR LEVELIZED BY-PRODUCT CREDIT	$0	$0.00 mills/KW-hr
30 - YEAR LEVELIZED CARRYING CHARGES (capital)	$1935159	$ 3.12 /KW-yr
30 - YEAR LEVELIZED BUSBAR COST OF POWER AT LEVELIZED CAPACITY FACTOR	$16759884	4.74 mills/KW-hr
30 - YEAR LEVELIZED COST EFFECTIVENESS SO2 REMOVED	$16759884	$1200.28 / ton

REFERENCES

1. Electric Power Research Institute, "Technical Assessment Guide," EPRI P-2410-SR, May 1982.

Appendix A: Conversions

English Symbol	Unit
F	Degree Fahrenheit
Btu	British Thermal Unit
ft	Foot
gal	Gallon
Hg	Mercury
hr	Hour
in.	Inch
kw	Kilowatt
lb	Pound

SI Metric Symbol	Unit
J	Joule
kg	Kilogram
kPa	Kilopascal
L	Litre
m	Metre
s	Second
W	Watt
C	Degree Celsius

Prefix	
k	Thousand
m	Million

Temperature

Degrees F = 1.8 degrees C + 32

Energy and Heat

1 Btu/lb = 2.33 kJ/kg
1 Btu/ft^2 = 11.35 kJ/m^2

Power

1 Btu/hr = 0.293 W

Volume

1 ft^3 = 0.0929 M^3
1 gal = .00379 M^3

Appendix A: Conversions

Pressure

1 in. Hg = 3.38 kPa
1 lb./sq. in. (psi) = 6.89 kPa

Length

1 in. = 2.54×10^{-2} m = 2.54 MM
1 ft = .305 m

Density

1 lb/ft^3 = 16 kg/m^3

Mass

1 lb = .454 kg

Appendix B: Boiler Performance Summary Sheet

The following tabulations are detailed summaries of unit performance, heating surface, fuel analysis and other key design data.

TABLE	DESCRIPTION	PAGE
B.1	Fuel Data	73
B.2	Performance Summary 200 MW Conventional Unit	74
B.3	Performance Summary 200 MW LIMB Unit	75
B.4	Performance Summary 400 MW Conventional Unit	76
B.5	Performance Summary 400 MW LIMB Unit	77
B.6	Performance Summary 600 MW Conventional Unit	78
B.7	Performance Summary 600 MW LIMB Unit	79
B.8	Heating Surface Summary 200 MW Conventional Unit	80
B.9	Heating Surface Summary 200 MW LIMB Unit	81
B.10	Heating Surface Summary 400 MW Conventional Unit	82
B.11	Heating Surface Summary 400 MW LIMB Unit	83
B.12	Heating Surface Summary 600 MW Conventional Unit	84
B.13	Heating Surface Summary 600 MW LIMB Unit	85

TABLE B.1 FUEL DATA

A	FUEL AS FIRED			
	SAMPLES ,			
	ANALYSES SPECIFIED			
	POWDER RIVER BASIN COAL			
COAL	KIND			WESTERN
	ASTM CLASS			SUB-BIT
	ASTM GROUP			C
	SOURCE MINE			
	SOURCE SEAM			
	SOURCE DISTRICT			
	SOURCE COUNTY			
	SOURCE STATE			WYOMING
	SIZE			1-1/4
	GRINDABILITY			64
	SURFACE MOISTURE, %			
	ASH SOFT.TEMP.,F (REDUCING)			2195
	PROX.ANAL.% MOISTURE, TOTAL			30.4
	PROX.ANAL.% VOLATILE MATTER			31.1
	PROX.ANAL.% FIXED CARBON			32.1
	PROX.ANAL.% ASH			6.4
	PROX.ANAL.% TOTAL			100.0
ULTIMATE ANALYSIS	FUEL			COAL
	$ BY			WT.
	ASH			6.40
	S			0.48
	H_2			3.40
	C			47.85
	C_1			0.03
	C_2H_8			
	C_2H_6			
	C_3H_8			
	C_4H_{10}			
	C_5H_{12}			
	C_6H_{14}			
	CO			
	CO_2			
	SO_2			
	H_2O			30.40
	N_2			0.62
	O_2			10.82
	TOTAL			100.00
	BTU/LB			8020
	BTU/CU FT AT 60F 30 IN.HG			

*EXCLUDING VALVES AND STATIC HEAD

UTILITY BOILER PERFORMANCE SUMMARY

BY RES APPD. DATE 3/6/86

BABCOCK & WILCOX

P52-225-10XO-1SO

TABLE B.2 PERFORMANCE SUMMARY 200 MW CONVENTIONAL UNIT

B1			PREDICTED PERFORMANCE		
STEAM LEAVING SH, M LB/HR			798.4	1330.7	
STEAM LEAVING RH1, M LB/HR			717	1195.0	
STEAM LEAVING RH2, M LB/HR			-	-	
TYPE OF FUEL			SPECIFIED	SPECIFIED	
LOAD CONDITION			60%	MCR	
EXCESS AIR LEAVING ECON., %			24.7	17	
NO. OF BURNERS IN OPERATION			12	12	
HEAT. AVAIL., MKB/HR (FUEL & HEATED AIR)			1210	1933	
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)			1178.4	1867	
HEAT CREDITS, MKB/HR			-	-	
FUEL INPUT, MKB/HR			1178.4	1867	
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)		146.9	232.8	
	FLUE GAS ENTERING AIR HTRS.		1283.7	1921.7	
	AIR TO BURNING EQUIPMENT		1121.5	1674.9	
	AIR HEATER LEAKAGE TO GAS (TOT)		131	139	
PRESSURE, PSIG	STEAM AT SH OUTLET		2440	2620	
	STEAM AT RH1 INLET		323	556	
	STEAM AT RH2 INLET		-	-	
	PRESSURE DROP: REHEATER 1		9	25	
	PRESSURE DROP: REHEATER 2		-	-	
	PRESSURE DROP: ECONOMIZER *		9	25	
	PRESSURE DROP: DRUM TO SH OUTLET		65	180	
TEMPERATURE, F	STEAM: LEAVING SUPERHEATER		1005	1005	
	STEAM: LEAVING REHEATER 1		1005	1005	
	STEAM: ENTERING REHEATER 1		567	622	
	STEAM: LEAVING REHEATER 2		-	-	
	STEAM: ENTERING REHEATER 2		-	-	
	FLUE GAS: LEAVING ECONOMIZER		666	750	
	FLUE GAS: LEAVING AH (EXCL. LKG)		261	300	
	FLUE GAS: LEAVING AH (INCL. LKG)		243	284	
	WATER ENTERING ECONOMIZER		435	478	
	AIR: ENTERING UNIT		60	60	
	AIR: LEAVING AIR HEATER PRI/SEC		566/573	670/635	
RESISTANCE, IN. OF WATER	GAS: FURNACE & CONVECTION BANKS				
	GAS: FLUES TO AH OUTLET				
	GAS: AIR HEATER				
	GAS:				
	GAS:				
	AIR: FUEL BURNERS & WINDBOX				
	AIR: DUCTS & FLOW METER				
	AIR: AIR HEATER				
	AIR:				
	AIR: TOT. FROM				
HEAT LOSS-EFF., %	DRY GAS		4.59	5.20	
	H_2 & H_2O IN FUEL		8.64	8.78	
	MOISTURE IN AIR		0.11	0.13	
	UNBURNED COMBUSTIBLE		0.15	0.15	
	RADIATION		0.31	0.20	
	UNACC. FOR & MFRS. MARGIN		1.00	1.00	
	TOTAL HEAT LOSS		14.80	15.46	
	*GROSS EFFICIENCY OF UNIT, %		85.20	84.54	
HEAT CREDITS ADJUSTMENT, %					
NET EFFICIENCY A.S.M.E. PTC-4.1, %					
FUEL EFFICIENCY, % (OUTPUT/FUEL INPUT)					
PULV., FAN & FEEDER	NO. IN USE PER BOILER		3	3/4	
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE		65	65	

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.29 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P52-225-10X0

TABLE B.3 PERFORMANCE SUMMARY 200 MW LIMB UNIT

				PREDICTED PERFORMANCE	
STEAM LEAVING SH, M LB/HR				798.4	1330.7
STEAM LEAVING RH^1, M LB/HR				717.0	1195.0
STEAM LEAVING RH^2, M LB/HR				-	-
TYPE OF FUEL				SPECIFIED	SPECIFIED
LOAD CONDITION				60%	MCR
EXCESS AIR LEAVING ECO#., %				30.5	17.9
NO. OF BURNERS IN OPERATION				12	12
HEAT. AVAIL., MKB/HR (FUEL & HEATED AIR)				1222.4	1932
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)				1179.7	1867.9
HEAT CREDITS, MKB/HR				-	-
FUEL INPUT, MKB/HR				1179.7	1867.9
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)			147.1	232.9
	FLUE GAS ENTERING AIR HTRS.			1338.5	1935.74
	AIR TO BURNING EQUIPMENT			1176.1	1688.8
	AIR HEATER LEAKAGE TO GAS (TOT)			131	139
PRESSURE, PSIG	STEAM AT SH OUTLET			2440	2620
	STEAM AT RH^1 INLET			323	556
	STEAM AT RH^2 INLET			-	-
PRESSURE DROP	REHEATER 1			9	25
	REHEATER 2			-	-
	ECONOMIZER *			9	25
	DRUM TO SH OUTLET			65	180
TEMPERATURE, F — STEAM	LEAVING SUPERHEATER			1005	1005
	LEAVING REHEATER 1			1005	1005
	ENTERING REHEATER 1			567	622
	LEAVING REHEATER 2			-	-
	ENTERING REHEATER 2			-	-
FLUE GAS	LEAVING ECONOMIZER			679	750
	LEAVING AH (EXCL. LKG)			257	300
	LEAVING AH (INCL. LKG)			239	284
	WATER ENTERING ECONOMIZER			435	478
AIR	ENTERING UNIT			60	60
	LEAVING AIR HEATER PRI/SEC			565/578	670/633
RESISTANCE, IN. OF WATER — GAS	FURNACE & CONVECTION BANKS				
	FLUES TO AH OUTLET				
	AIR HEATER				
AIR	FUEL BURNERS & WINDBOX				
	DUCTS & FLOW METER				
	AIR HEATER				
	TOT. FROM				
*HEAT LOSS-EFF., %	DRY GAS			4.59	5.20
	H_2 & H_2O IN FUEL			8.63	8.78
	MOISTURE IN AIR			.12	0.13
	UNBURNED COMBUSTIBLE			.15	0.15
	RADIATION			.31	0.20
	UNACC. FOR & MFRS. MARGIN			1.0	1.00
	INJECTION NOZZLE LOSS			0	0
	HEAT OF REACTION			- .05	- .02
	INJECTION AIR LOSS			.10	.04
	*GROSS EFFICIENCY			85.15	84.52
Ca (OH_2) REQ'D, MLBS/HR.					
PULV./FAN & FEEDER	NO. IN USE PER BOILER			3	3/4
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE			65	65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.29 IN. HG. BAROMETRIC PRESSURE. ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P52-255-11X1

TABLE B.4 PERFORMANCE SUMMARY 400 MW CONVENTIONAL UNIT

				PREDICTED PERFORMANCE	
STEAM LEAVING SH. M LB/HR				1820	3034.5
STEAM LEAVING RH^1, M LB/HR				1640	2707
STEAM LEAVING RH^2, M LB/HR				-	-
TYPE OF FUEL				SPECIFIED	SPECIFIED
LOAD CONDITION				60%	MCR
EXCESS AIR LEAVING ECON., %				24.7	17
NO. OF BURNERS IN OPERATION				18	24
HEAT. AVAIL..MKB/HR (FUEL & HEATED AIR)				2767	4343
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)				2685	4206
HEAT CREDITS, MKB/HR				-	-
FUEL INPUT. MKB/HR				2685	4206
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)			335	524.5
	FLUE GAS ENTERING AIR HTRS.			2925	4330
	AIR TO BURNING EQUIPMENT			2555	3774
	AIR HEATER LEAKAGE TO GAS (TOT)			228	246
PRESSURE, PSIG	STEAM AT SH OUTLET			2440	2620
	STEAM AT RH^1 INLET			395	589
	STEAM AT RH^2 INLET			-	-
	*PRESSURE DROP REHEATER 1			9	25
	REHEATER 2			-	-
	ECONOMIZER			9	25
	DRUM TO SH OUTLET			65	180
TEMPERATURE, F	STEAM LEAVING SUPERHEATER			1005	1005
	STEAM LEAVING REHEATER 1			1005	1005
	STEAM ENTERING REHEATER 1			573	633
	STEAM LEAVING REHEATER 2			-	-
	STEAM ENTERING REHEATER 2			-	-
	FLUE GAS LEAVING ECONOMIZER			682	735
	FLUE GAS LEAVING AH (EXCL. LKG)			269	297
	FLUE GAS LEAVING AH (INCL. LKG)			255	285
	WATER ENTERING ECONOMIZER			438	485
	AIR ENTERING UNIT			60	60
	AIR LEAVING AIR HEATER PRI/SEC			568/585	655/613
RESISTANCE, IN. OF WATER	GAS FURNACE & CONVECTION BANKS				
	GAS FLUES TO AH OUTLET				
	GAS AIR HEATER				
	AIR FUEL BURNERS & WINDBOX				
	AIR DUCTS & FLOW METER				
	AIR AIR HEATER				
	TOT. FROM				
*HEAT LOSS-EFF., %	DRY GAS			4.69	5.20
	H_2 & H_2O IN FUEL			8.65	8.78
	MOISTURE IN AIR			0.12	0.13
	UNBURNED COMBUSTIBLE			0.15	0.15
	RADIATION			0.26	0.16
	UNACC. FOR & MFRS. MARGIN			1.00	1.00
	TOTAL HEAT LOSS			14.87	15.42
	*GROSS EFFICIENCY OF UNIT, %			85.13	84.58
HEAT CREDITS ADJUSTMENT, %				-	-
NET EFFICIENCY A.S.M.E. PTC-4.1, %				-	-
FUEL EFFICIENCY, %, (OUTPUT/FUEL INPUT)				-	-
PULV., FAN & FEEDER	NO. IN USE PER BOILER			3	4/5
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE			65	65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.29 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P52-225-1Y2

TABLE B.5 PERFORMANCE SUMMARY 400 MW LIMB UNIT

				PREDICTED PERFORMANCE	
STEAM LEAVING SH. M LB/HR				1820	3034
STEAM LEAVING RH^1, M LB/HR				1640	2707
STEAM LEAVING RH^2, M LB/HR				-	-
TYPE OF FUEL				SPECIFIED	SPECIFIED
LOAD CONDITION				60%	MCR
EXCESS AIR LEAVING ECON., %				29.4	18.1
NO. OF BURNERS IN OPERATION				18	24
HEAT. AVAIL.. MKB/HR (FUEL & HEATED AIR)				2788.3	4342
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)				2723	4245.7
HEAT CREDITS, MKB/HR				-	-
FUEL INPUT. MKB/HR				2723	4245.7
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)			339.5	529.7
	FLUE GAS ENTERING AIR HTRS.			3037	4368.3
	AIR TO BURNING EQUIPMENT			2665	3811.84
	AIR HEATER LEAKAGE TO GAS (TOT)			280	292
PRESSURE, PSIG	STEAM AT SH OUTLET			2440	2620
	STEAM AT RH^1 INLET			395	589
	STEAM AT RH^2 INLET			-	-
PRESSURE DROP	REHEATER 1			9	25
	REHEATER 2			-	-
	ECONOMIZER			9	25
	DRUM TO SH OUTLET			65	180
TEMPERATURE, F STEAM	LEAVING SUPERHEATER			1005	1005
	LEAVING REHEATER 1			1005	1005
	ENTERING REHEATER 1			573	633
	LEAVING REHEATER 2			-	-
	ENTERING REHEATER 2			-	-
FLUE GAS	LEAVING ECONOMIZER			688	737
	LEAVING AH (EXCL. LKG)			277	297
	LEAVING AH (INCL. LKG)			259	286
	WATER ENTERING ECONOMIZER			438	485
AIR	ENTERING UNIT			60	60
	LEAVING AIR HEATER PRI/SEC			573/593	655/615
RESISTANCE, IN. OF WATER GAS	FURNACE & CONVECTION BANKS				
	FLUES TO AH OUTLET				
	AIR HEATER				
AIR	FUEL BURNERS & WINDBOX				
	DUCTS & FLOW METER				
	AIR HEATER				
	TOT. FROM				
*HEAT LOSS-EFF., %	DRY GAS			4.69	5.20
	H_2 & H_2O IN FUEL			8.68	8.78
	MOISTURE IN AIR			0.13	0.13
	UNBURNED COMBUSTIBLE			0.15	0.15
	RADIATION			0.26	0.16
	UNACC. FOR & MFRS. MARGIN			1.00	1.00
	INJECTION NOZZLE LOSS			.82	.73
	HEAT OF REACTION			- .03	- .01
	INJECTION AIR LOSS			.34	.04
	*GROSS EFFICIENCY, %			83.96	83.80
Ca $(OH)_2$ REQ'D, MLBS/HR				10.9	20.6
PULV., FAN & FEEDER	NO. IN USE P.R BOILER			3	4/5
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE			65	65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.29 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P52-225-3Y1

TABLE B.6 PERFORMANCE SUMMARY 600 MW CONVENTIONAL UNIT

				PREDICTED PERFORMANCE	
STEAM LEAVING SH. M LB/HR				2534.8	4224.9
STEAM LEAVING RH^1, M LB/HR				2292.5	3764.3
STEAM LEAVING RH^2, M LB/HR				-	-
TYPE OF FUEL				SPECIFIED	SPECIFIED
LOAD CONDITION				60%	MCR
EXCESS AIR LEAVING ECON., %				24.5	17.0
NO. OF BURNERS IN OPERATION				28	35
HEAT. AVAIL., MKB/HR (FUEL & HEATED AIR)				3809.5	6001.1
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)				3724.3	5810.9
HEAT CREDITS, MKB/HR				-	-
FUEL INPUT, MKB/HR				3724.3	5810.9
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)			464.4	724.5
	FLUE GAS ENTERING AIR HTRS.			4050.05	5979.30
	AIR TO BURNING EQUIPMENT			3543.2	5211.1
	AIR HEATER LEAKAGE			162	175
PRESSURE, PSIG	STEAM AT SH OUTLET			2437	2620
	STEAM AT RH^1 INLET			369	612
	STEAM AT RH^2 INLET			-	-
PRESSURE DROP	REHEATER 1			19	32
	REHEATER 2			-	-
	ECONOMIZER *			9	25
	DRUM TO SH OUTLET			65	180
TEMPERATURE, F	STEAM: LEAVING SUPERHEATER			1005	1005
	LEAVING REHEATER 1			1005	1005
	ENTERING REHEATER 1			577	641
	LEAVING REHEATER 2			-	-
	ENTERING REHEATER 2			-	-
	FLUE GAS: LEAVING ECONOMIZER			655	740
	LEAVING AH (EXCL. LKG)			265	300
	LEAVING AH (INCL. LKG)			250	285
	WATER ENTERING ECONOMIZER			440	490
	AIR: ENTERING UNIT			60	60
	LEAVING AIR HEATER PRI/SEC			588/585	645/625
RESISTANCE, IN. OF WATER	GAS: FURNACE & CONVECTION BANKS				
	FLUES TO AH OUTLET				
	AIR HEATER				
	AIR: FUEL BURNERS & WINDBOX				
	DUCTS & FLOW METER				
	AIR HEATER				
	TOT. FROM				
*HEAT LOSS-EFF., %	DRY GAS			4.68	5.20
	H_2 & H_2O IN FUEL			8.65	8.78
	MOISTURE IN AIR			0.12	0.13
	UNBURNED COMBUSTIBLE			0.15	0.15
	RADIATION			0.24	0.15
	UNACC. FOR & MFRS. MARGIN			1.00	1.00
	TOTAL HEAT LOSS			14.84	15.41
	*GROSS EFFICIENCY OF UNIT, %			85.16	84.59
HEAT CREDITS ADJUSTMENT, %					
NET EFFICIENCY A.S.M.E. PTC-4.1, %					
FUEL EFFICIENCY, % (OUTPUT/FUEL INPUT)					
PULVERIZER & FEEDER	NO. IN USE PER BOILER			4	5/6
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE			65	65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, @ 29.29 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & IN ARRANGEMENT SHOWN ON DRAWING P52-225-2Y0

TABLE B.7 PERFORMANCE SUMMARY 600 MW LIMB UNIT

				PREDICTED PERFORMANCE	
STEAM LEAVING SH, M LB/HR				2534.8	4224.9
STEAM LEAVING RH^1, M LB/HR				2292.5	3764.3
STEAM LEAVING RH^2, M LB/HR				-	-
TYPE OF FUEL				SPECIFIED	SPECIFIED
LOAD CONDITION				60%	MCR
EXCESS AIR LEAVING ECON., %				27	18.1
NO. OF BURNERS IN OPERATION				28	35
HEAT. AVAIL., MKB/HR (FUEL & HEATED AIR)				3858	6048.3
TOTAL INPUT, MKB/HR (FUEL & HT. CREDITS)				3763	5857.7
HEAT CREDITS, MKB/HR				-	-
FUEL INPUT, MKB/HR				3763	5857.7
QUANTITY M LB/HR	FUEL (MCFH-NAT. GAS)			469.25	730.4
	FLUE GAS ENTERING AIR HTRS.			4171.8	6075.8
	AIR TO BURNING EQUIPMENT			3659.6	5302.0
	AIR HEATER LEAKAGE			162	175.0
PRESSURE, PSIG	STEAM AT SH OUTLET			2437	2620
	STEAM AT RH^1 INLET			369	612
	STEAM AT RH^2 INLET			-	-
	REHEATER 1			19	32
	REHEATER 2			-	-
	ECONOMIZER *			9	25
	DRUM TO SH OUTLET			65	180
TEMPERATURE, F	STEAM LEAVING SUPERHEATER			1005	1005
	STEAM LEAVING REHEATER 1			1005	1005
	STEAM ENTERING REHEATER 1			577	641
	STEAM LEAVING REHEATER 2			-	-
	STEAM ENTERING REHEATER 2			-	-
	FLUE GAS LEAVING ECONOMIZER			675	740
	FLUE GAS LEAVING AH (EXCL. LKG)			275	300
	FLUE GAS LEAVING AH (INCL. LKG)			260	287
	WATER ENTERING ECONOMIZER			440	490
	AIR ENTERING UNIT			60	60
	AIR LEAVING AIR HEATER PRI/SEC			588/585	645/625
RESISTANCE, IN. OF WATER	GAS: FURNACE & CONVECTION BANKS				
	GAS: FLUES TO AH OUTLET				
	GAS: AIR HEATER				
	GAS:				
	GAS:				
	AIR: FUEL BURNERS & WINDBOX				
	AIR: DUCTS & FLOW METER				
	AIR: AIR HEATER				
	AIR:				
	AIR: TOT. FROM				
HEAT LOSS-ETA, %	DRY GAS			4.68	5.20
	H_2 & H_2O IN FUEL			8.69	8.78
	MOISTURE IN AIR			0.13	0.13
	UNBURNED COMBUSTIBLE			0.15	0.15
	RADIATION			0.24	0.15
	UNACC. FOR & MFRS. MARGIN			1.00	1.00
	INJECTION NOZZLE LOSS			.68	.63
	HEAT OF REACTION			-.03	-.01
	INJECTION AIR			.36	.04
	*GROSS EFFICIENCY			84.10	83.91
Ca $(OH)_2$ REQ'D, MLBS/HR				15.3	28.4
PULV., FAN & STOKER	NO. IN USE PER BOILER			4	5
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE			65	65

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 29.29 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING P52-225-4Y1

TABLE B.8 HEATING SURFACE SUMMARY 200 MW CONVENTIONAL UNIT

C	EQUIPMENT PER UNIT	
TYPE	CAROLINA RADIANT BOILER	
SIZE		
DESIGN PRESSURE SH/RH 2950/775 PSIG		
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	17,860
	SUPERHEATER (PERIPHERAL)	8,365
	SUPERHEATER (ROOF)	1,465
	TOTAL FURNACE HEATING SURFACE	27,690
CONVECTION	SATURATED (CIRCUMFERENTIAL)	3,500
	SUPERHEATER (CIRCUMFERENTIAL)	48,850
	REHEATER 1 (CIRCUMFERENTIAL	71,703
	REHEATER 2 (CIRCUMFERENTIAL)	
	ECONOMIZER	25,900
	TOTAL CONVECTION HEATING SURFACE	149,953
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		177,643
FLAT PROJECTED FURNACE HEATING SURFACE		
TO FACE OF PLATENS 24" CENTERS		20,900
TO FACE OF CONVECTION SURFACE 12" CENTERS		28,075
FURNACE VOLUME, CU FT		155,112
AIR HEATER	TYPE ROTHEMUHLE TWINFLOW NO. 1	
	TOTAL HEATING SURFACE, SQ FT 414,139	
FUEL BURNER	TYPE DUAL REGISTER	
	NO. 16	
PULVERIZER	TYPE MPS SIZE 67 NO. 4	
	CAPACITY OF 3 PULV. IS 133.07 M LB STEAM/HR BASED ON 64 GRIND	
	8020 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE	
	FOR 7.26 M LB COAL/PULV.-HR AT 65 % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS 64, MAXIMUM SURFACE MOISTURE IS 30.4% REQUIRING 670 F AIR	
STEAM TEMP. CONTROL	SUPERHEAT BY SPRAY ATTEMPERATION	
	REHEAT BY GAS BIASING	
UNIT CONSTRUCTION FEATURES	INDOOR	
	BALANCED DRAFT	
	MEMBRANED WALLS	

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS	NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
CONVENTIONAL
200 MW BOILER

TABLE B.9 HEATING SURFACE SUMMARY 200 MW LIMB UNIT

		EQUIPMENT PER UNIT
TYPE		CAROLINA RADIANT BOILER
SIZE		
		DESIGN PRESSURE SH/RH 2950/775 PSIG
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	20,090
	SUPERHEATER (PERIPHERAL)	0
	SUPERHEATER (ROOF)	1,465
	TOTAL FURNACE HEATING SURFACE	21,555
PRESSURE PART HEATING SURFACE, SQ FT — CONVECTION	SATURATED (CIRCUMFERENTIAL)	3,978
	SUPERHEATER (CIRCUMFERENTIAL)	66,037
	REHEATER 1 (CIRCUMFERENTIAL)	78,893
	SUPERHEATER (PERIPHERAL)	7,537
	ECONOMIZER	15,898
	TOTAL CONVECTION HEATING SURFACE	172,343
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		193,898
FLAT PROJECTED FURNACE HEATING SURFACE		
	TO FACE OF FURNACE SCREEN	22,230
	TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CU FT		175,350
AIR HEATER	TYPE ROTHEMUHLE TIWNFLOW NO. 1	
	TOTAL HEATING SURFACE, SQ FT 414,139	
FUEL BURNER	TYPE DUAL REGISTER	
	NO. 16	
PULVERIZER	TYPE MPS SIZE 67 NO. 4	
	CAPACITY OF 3 PULV. IS 133Q7M LB STEAM/HR BASED ON 64 GRIND	
	8020 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE	
	FOR 726 M LB COAL/PULV.-HR AT 65 % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS 64 , MAXIMUM SURFACE MOISTURE IS 30.4% REQUIRING 670 F AIR	
STEAM TEMP. CONTROL	SUPERHEAT BY SPRAY ATTEMPERATION	
	REHEAT BY GAS BIASING	
UNIT CONSTRUCTION FEATURES	INDOOR	
	BALANCED DRAFT	
	MEMBRANED WALLS	

*CORRESPONDING TO ASB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS: NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
LIMB
200 MW BOILER

TABLE B.10 HEATING SURFACE SUMMARY 400 MW CONVENTIONAL UNIT

[c]	EQUIPMENT PER UNIT		
TYPE	CAROLINA RADIANT BOILER		
SIZE			
DESIGN PRESSURE SH/RH 2950/775 PSIG			
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)		
	WATER COOLED (PROJECTED)		29,530
	SUPERHEATER (PHERIPHERAL)		24,096
	SUPERHEATER (ROOF		2,605
	TOTAL FURNACE HEATING SURFACE		56,231
CONVECTION	SATURATED (CIRCUMFERENTIAL)		5,830
	SUPERHEATER (CIRCUMFERENTIAL)		67,632
	REHEATER 1 (CIRCUMFERENTIAL		85,012
	REHEATER 2 (CIRCUMFERENTIAL)		-
	ECONOMIZER		121,004
	TOTAL CONVECTION HEATING SURFACE		279,478
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.			335,709
FLAT PROJECTED FURNACE HEATING SURFACE			
TO FACE OF PLATENS	24" CENTERS		42,436
TO FACE OF CONVECTION SURFACE	12" CENTERS		57,126
FURNACE VOLUME, CU FT	342,465		
AIR HEATER	TYPE ROTHEMUHLE TWINFLOW	NO. 1	
	TOTAL HEATING SURFACE, SQ FT	792,289	
FUEL BURNER	TYPE	DUAL REGISTER	
	NO.	30	
PULVERIZER	TYPE MPS	SIZE 89	NO. 5
	CAPACITY OF 4 PULV. IS 3034 M LB STEAM/HR BASED ON 64		GRIND
	8020 BTU COAL AT 65	% THRU 200 U.S.S. SIEVE	
	FOR 132 M LB COAL/PULV.-HR AT 65 % THRU 200 U.S.S. SIEVE MIN. GRIND		
	IS 64, MAXIMUM SURFACE MOISTURE IS 30.4% REQUIRING 655		F AIR
STEAM TEMP. CONTROL	SUPERHEAT BY SPRAY ATTEMPERATION		
	REHEAT BY GAS BIASING		
UNIT CONSTRUCTION FEATURES	INDOOR		
	BALANCED DRAFT		
	MEMBRANED WALLS		

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS	NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
CONVENTIONAL 400 MW BOILER

TABLE B.11 HEATING SURFACE SUMMARY 400 MW LIMB UNIT

C	EQUIPMENT PER UNIT		
TYPE	CAROLINA RADIANT BOILER		
SIZE			
DESIGN PRESSURE SH/RH 2950/775 PSIG			
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)		
	WATER COOLED (PROJECTED)	30,320	
	SUPERHEATER (PERIPHERAL)	8,200	
	SUPERHEATER (ROOF	2,589	
	TOTAL FURNACE HEATING SURFACE	41,109	
CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,450	
	SUPERHEATER (CIRCUMFERENTIAL)	108,571	
	REHEATER 1 (CIRCUMFERENTIAL	77,157	
	SUPERHEATER (A_p)	8,442	
	ECONOMIZER	110,602	
	TOTAL CONVECTION HEATING SURFACE	312,222	
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		353,331	
FLAT PROJECTED FURNACE HEATING SURFACE			
	TO FACE OF FURNACE SCREEN	54,814	
	TO FACE OF CONVECTION SURFACE	-	
FURNACE VOLUME, CU FT		353,450	
AIR HEATER	TYPE ROTHEMUHLE TWINFLOW NO. 1		
	TOTAL HEATING SURFACE, SQ FT 792,289		
FUEL BURNER	TYPE DUAL REGISTER		
	NO. 30		
PULVERIZER	TYPE MPS SIZE 89 NO. 5		
	CAPACITY OF 4 PULV. IS 3034 M LB STEAM/HR BASED ON 64 GRIND		
	8020 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE		
	FOR 132 M LB COAL/PULV.-HR AT 65 % THRU 200 U.S.S. SIEVE MIN. GRIND		
	IS 64, MAXIMUM SURFACE MOISTURE IS 30.4% REQUIRING 655 F AIR		
STEAM TEMP. CONTROL	SUPERHEAT BY SPRAY ATTEMPERATION		
	REHEAT BY GAS BIASING		
UNIT CONSTRUCTION FEATURES	INDOOR		
	BALANCED DRAFT		
	MEMBRANED WALLS		

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS	NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
LIMB 400 MW BOILER

TABLE B.12 HEATING SURFACE SUMMARY 600 MW CONVENTIONAL UNIT

EQUIPMENT PER UNIT

TYPE CAROLINA RADIANT BOILER

SIZE

DESIGN PRESSURE SH/RH 2950/775 PSIG

PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	38,770
	SUPERHEATER PHERIPHERAL	36,087
	SUPERHEATER ROOF	3,254
	TOTAL FURNACE HEATING SURFACE	78,111
CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,690
	SUPERHEATER (CIRCUMFERENTIAL)	77,114
	REHEATER 1 (CIRCUMFERENTIAL	106,479
	SUPERHEATER (PROJECTED)	24,750
	ECONOMIZER	172,310
	TOTAL CONVECTION HEATING SURFACE	388,343
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		466,454
FLAT PROJECTED FURNACE HEATING SURFACE		
TO FACE OF PLATENS		57,437
TO FACE OF CONVECTION SURFACE		79,997
FURNACE VOLUME, CU FT		511,360
AIR HEATER	TYPE ROTHEMUHLE TWINFLOW NO. 2	
	TOTAL HEATING SURFACE, SQ FT 535,925 (EACH)	

FUEL BURNER
TYPE DUAL REGISTER
NO. 42

PULVERIZER
TYPE MPS SIZE 89N NO. 6
CAPACITY OF 5 PULV. IS 42249 M LB STEAM/HR BASED ON 64 GRIND
8020 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE
FOR 1458 M LB COAL/PULV.-HR AT 65% THRU 200 U.S.S. SIEVE MIN. GRIND
IS 64, MAXIMUM SURFACE MOISTURE IS 30.4% REQUIRING 645 F AIR

STEAM TEMP. CONTROL
SUPERHEATER BY SPRAY ATTEMPERATION
REHEAT BY GAS BIASING

UNIT CONSTRUCTION FEATURES
INDOOR
BALANCED DRAFT
MEMBRANED WALLS

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
CONVENTIONAL
600 MW BOILER

TABLE B.13 HEATING SURFACE SUMMARY 600 MW LIMB UNIT

[C] EQUIPMENT PER UNIT		
TYPE CAROLINA RADIANT BOILER		
SIZE		
DESIGN PRESSURE SH/RH 2950/775 PSIG		
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	39,740
	SUPERHEATER (PERIPHERAL)	16,874
	SUPERHEATER (ROOF)	3,241
	TOTAL FURNACE HEATING SURFACE	59,855
CONVECTION	SATURATED (CIRCUMFERENTIAL)	9,230
	SUPERHEATER (CIRCUMFERENTIAL)	106,495
	REHEATER 1 (CIRCUMFERENTIAL	123,894
	SUPERHEATER (PERIPHERAL)	27,606
	ECONOMIZER	135,377
	TOTAL CONVECTION HEATING SURFACE	402,602
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		462,457
FLAT PROJECTED FURNACE HEATING SURFACE		
TO FARSIDE SCREEN		62,384
TO FACE OF CONVECTION SURFACE		
FURNACE VOLUME, CU FT		530,816
AIR HEATER	TYPE ROTHEMUHLE TWINFLOW NO. 2	
	TOTAL HEATING SURFACE, SQ FT 533,925 (EACH)	
FUEL BURNER	TYPE DUAL REGISTER	
	NO. 42	
PULVERIZER	TYPE MPS SIZE 89N NO. 6	
	CAPACITY OF 5 PULV. IS 42249 M LB STEAM/HR BASED ON 64 GRIND	
	8020 BTU COAL AT 65 % THRU 200 U.S.S. SIEVE	
	FOR 458 M LB COAL/PULV.-HR AT 65 % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS 64, MAXIMUM SURFACE MOISTURE IS 30.4 REQUIRING 645 F AIR	
STEAM TEMP. CONTROL	SUPERHEATER BY SPRAY ATTEMPERATION	
	REHEAT STEAM BY GAS BIASING	
UNIT CONSTRUCTION FEATURES	INDOOR	
	BALANCED DRAFT	
	MEMBRANED WALLS	

*CORRESPONDING TO ABB. METHOD PAR. 1.07 A.S.M.E. PTC-4.1

REVISIONS	NO.	DESCRIPTION	BY	DATE

EPA LIMB PROJECT
LIMB
600 MW BOILER